



Alberta Oxides of Nitrogen
Emissions Forecast
1980 to 2000

RMD Report 83-26

Alberta

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ALBERTA OXIDES OF NITROGEN EMISSIONS FORECAST

1980 to 2000

**RESEARCH MANAGEMENT DIVISION
Alberta Environment**

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1980 to 2000

by

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Division of Bow Valley Resource Services Ltd.**

for

**RESEARCH MANAGEMENT DIVISION
Alberta Environment**

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TABLE OF CONTENTS

	Page
LIST OF TABLES	viii
LIST OF FIGURES	x
GUIDE TO SYMBOLS	xi
ABSTRACT	xii
ACKNOWLEDGEMENTS	xiii
 1. EXECUTIVE SUMMARY	 1
1.1 Growth Profiles	1
1.1.1 Scenario A	2
1.1.1.1 Population	2
1.1.1.2 Transportation	2
1.1.1.3 Electrical Generation	2
1.1.1.4 Industrial Growth	2
1.1.1.5 Natural Gas	2
1.1.2 Scenario B	3
1.1.2.1 Population	3
1.1.2.2 Transportation	3
1.1.2.3 Electrical Generation	3
1.1.2.4 Industrial Growth	3
1.1.2.5 Natural Gas	3
1.2 Oxides of Nitrogen Emissions	3
1.2.1 Emission Factors	4
1.2.2 Emission Forecasts	4
1.3 Summary and Recommendations	10
 2. INTRODUCTION	 11
 3. GROWTH FORECASTS	 12
3.1 Population Growth Projections	12
3.2 Transportation	14
3.2.1 Private Passenger Cars	14
3.2.2 Commercial Vehicles	15
3.2.3 Railways	21
3.3 Electric Utility Growth	21
3.4 Industrial Growth Profile	21
3.4.1 Residential and Commercial Gas Requirements ..	25
3.4.2 Electric Generation Gas Requirements	25
3.4.3 Oil Sands Gas Requirements	25
3.4.4 Other Industrial Gas Requirements	27
3.4.5 Natural Gas Industry	28

TABLE OF CONTENTS (CONTINUED)

	Page
4. OXIDES OF NITROGEN EMISSIONS FORECAST	33
4.1 Natural Gas Industry	34
4.1.1 Fuel Gas Usage	34
4.1.1.1 Field	36
4.1.1.2 Gathering	36
4.1.1.3 Processing Plants	37
4.1.1.4 Injection	38
4.1.1.5 Transportation	38
4.1.1.6 Reprocessing	38
4.1.2 Oxides of Nitrogen Sources	39
4.1.2.1 Reciprocating Compressor Engines	39
4.1.2.2 Gas Turbines	41
4.1.2.3 Large Electric Motors	42
4.1.2.4 Heaters and Boilers	43
4.1.2.5 Incinerators	43
4.1.3 Potential Oxides of Nitrogen Emissions	43
4.1.3.1 Present Technology	44
4.1.3.2 Best Practicable Technology	44
4.1.3.3 Electric Motor Substitution Option	44
4.1.3.4 Best Available Technology	44
4.1.3.5 Summary	46
4.2 Electric Utilities	46
4.2.1 Emission Factors	46
4.2.2 Potential Oxides of Nitrogen Emissions	46
4.2.2.1 Present Technology	49
4.2.2.2 Best Practicable Technology	49
4.2.2.3 Best Available Technology	49
4.2.2.4 Summary	50
4.3 Oil Sands	50
4.3.1 Emissions Factors	50
4.3.2 Potential Oxides of Nitrogen Emissions	56
4.3.2.1 Present Technology	56
4.3.2.2 Best Practicable Technology	56
4.3.2.3 Best Available Technology	56
4.3.2.4 Summary	57
4.4 Other Industries	57
4.4.1 Potential Oxides of Nitrogen Emissions	57
4.4.1.1 Present Technology	57
4.4.1.2 Best Practicable Technology	60
4.4.1.3 Best Available Technology	60
4.4.1.4 Summary	60
4.5 Transportation	60
4.5.1 Passenger Cars	60
4.5.1.1 Present Technology	64
4.5.1.2 Best Practicable Technology	67
4.5.1.3 Best Available Technology	67

TABLE OF CONTENTS (CONCLUDED)

	Page
4.5.2 Commercial Vehicles	67
4.5.2.1 Present Technology	68
4.5.2.2. Best Practicable Technology	68
4.5.2.3 Best Available Technology	71
4.5.3 Railways	71
4.5.3.1 Present Technology	71
4.5.3.2 Best Practicable Technology	74
4.5.3.3 Best Available Technology	74
4.5.4 Summary	74
4.6 Residential and Commercial	74
4.6.1 Residential Sector	74
4.6.1.1 Present Technology	76
4.6.1.2 Best Practicable Technology	76
4.6.1.3 Best Available Technology	79
4.6.2 Commercial Sector	79
4.6.2.1 Present Technology	82
4.6.2.2 Best Practicable Technology	82
4.6.2.3 Best Available Technology	82
4.6.3 Residential and Commercial Summary	82
4.7 Total Alberta Forecast	84
4.7.1 Scenario A	84
4.7.2 Scenario B	85
4.7.3 Consolidated Forecast	86
4.7.4 Other Strategies	90
4.7.5 Forecast Sensitivity	90
5. CONCLUSIONS AND RECOMMENDATIONS	92
6. REFERENCES CITED	93
7. APPENDIX	95

LIST OF TABLES

	Page
1. Summary of NO _x Emission Factors Used for Stationary Sources	5
2. Summary of NO _x Emission Factors Used for Mobile Sources	6
3. Passenger Car Population Forecast	16
4. Commercial Vehicle Population Forecast	19
5. Railways Diesel Fuel Oil Consumption Forecast	22
6. Supply of Electric Energy Requirements by Source Type	23
7. Scenario A: Alberta Natural Gas Requirements Forecast	29
8. Scenario B: Alberta Natural Gas Requirements Forecast	30
9. Total Alberta Marketable Gas Deliveries Forecast..	31
10. Natural Gas Industry Fuel Gas Usage as a Percentage of Total Deliveries (1980 to 2000)	35
11. Natural Gas Industry NO _x Source Emission Factors..	40
12. Natural Gas Industry Overall NO _x Emission Factors: Present Technology	45
13. Natural Gas Industry Oxides of Nitrogen Emissions Forecast	47
14. Electric Utilities NO _x Emission Factors	51
15. Electric Utilities Oxides of Nitrogen Emissions Forecast	52
16. Oil Sands Composite NO _x Emission Factors	55
17. Oil Sands Oxides of Nitrogen Emissions Forecast ..	58
18. Other Industries NO _x Emission Factors	61
19. Other Industries Oxides of Nitrogen Emissions Forecast	63

LIST OF TABLES (CONCLUDED)

	Page
20. Composite NO _x Emission Factors for Passenger Cars	65
21. Passenger Cars Oxides of Nitrogen Emissions Forecast	66
22. Composite NO _x Emission Factors for Commercial Vehicles	69
23. Commercial Vehicles Oxides of Nitrogen Emissions Forecast	70
24. Railway NO _x Emission Factor	72
25. Railway Oxides of Nitrogen Emissions Forecast	73
26. Residential Sector NO _x Emission Factors	77
27. Residential Sector Oxides of Nitrogen Emissions Forecast	78
28. Commercial Sector NO _x Emission Factors	80
29. Commercial Sector Oxides of Nitrogen Emissions Forecast	81
30. Consolidated Oxides of Nitrogen Emissions Forecasts for Alberta	87
31. Oxides of Nitrogen Emissions Forecast: Scenario A, Present Technology	96
32. Oxides of Nitrogen Emissions Forecast: Scenario A, Best Practicable Technology	97
33. Oxides of Nitrogen Emissions Forecast: Scenario A, Best Available Technology	98
34. Oxides of Nitrogen Emissions Forecast: Scenario B, Present Technology	99
35. Oxides of Nitrogen Emissions Forecast: Scenario B, Best Practicable Technology	100
36. Oxides of Nitrogen Emissions Forecast: Scenario B, Best Available Technology	101

LIST OF FIGURES

	Page
1. Total Alberta Oxides of Nitrogen Emissions Forecast 1980 to 2000	7
2. Oxides of Nitrogen Source and Emission Estimate for 1980 and 2000	9
3. Population Growth of Passenger Cars	17
4. Population Growth of Commercial Vehicles	20
5. Electrical Energy Requirements Forecast	24
6. Oil Sands Production Forecast	26
7. Alberta Marketable Gas Deliveries Forecast	32
8. Natural Gas Industry Emissions Forecast	48
9. Electric Utilities Emissions Forecast	53
10. Oil Sands Emissions Forecast	59
11. Other Industries Emissions Forecast	62
12. Transportation Sector Emissions Forecast	75
13. Residential and Commercial Emissions Forecast	83
14. Total Alberta Oxides of Nitrogen Emissions Forecast 1980 to 2000	88
15. NO _x Emission Comparison by Sector and Technology for 1980 and 2000	89

GUIDE TO SYMBOLS

PJ	petajoule (10^{15} joules)
PJ/a	petajoule per annum
m^3	cubic metre
m^3/d	cubic metre per day
kg	kilogram (10^3 grams)
kg/m^3	kilogram per cubic metre
$kg/10^3m^3$	kilogram per 10^3 cubic metre
t	tonne (10^3 kilograms)
$kg/10^6m^3$	kilogram per 10^6 cubic metre
MW	megawatt (10^6 watts)
GW	gigawatt (10^9 watts)
GW h	gigawatt hour
ng	nanogram (10^{-9} gram)
ng/J	nanogram per joule
kg/t	kilogram per tonne
t/d	tonne per day
g/km	gram per kilometer
$kg/10^3L$	kilogram per 10^3 litre
kg/m^3SCO	kilogram per cubic metre of synthetic crude oil
km	kilometre
10^6L	10^6 litre

ABSTRACT

Potential oxides of nitrogen emissions from industrial, commercial, residential, and transportation sources in Alberta are analysed and forecasts to the year 2000 are presented.

To prepare the emission forecasts two growth profiles, referred to as Scenario A and Scenario B, are developed. Scenario A assumes a reasonably optimistic high growth while Scenario B assumes a more conservative approach to provincial growth. These growth profiles include assessments of population; transportation; electrical generation; industrial growth; production, processing, and transmission of natural gas; and consumption of natural gas within Alberta.

Using the two growth scenarios, potential emissions of oxides of nitrogen are estimated by employing present, best practicable, and best available technology. For best practicable technology, the starting year for implementation in all sectors is 1985 and a five-year phase in period is used. For best available technology, the starting year is 1990 and it is assumed that all existing sources have already reached the emission levels corresponding to best practicable technology. Again, a five-year phase in period is assumed.

The oxides of nitrogen forecasts show a continuing increase to levels of 1833 and 1502 t/d, respectively, for scenarios A and B by 2000 compared to the current levels of 931 t/d. Best practicable technology would be able to reduce the 2000 levels to 966 and 792 t/d for the two growth scenarios, whereas the application of best available technology would reduce the levels to 478 and 404 t/d.

Transportation sources are the most significant sources of oxides of nitrogen emissions throughout the entire forecast period and represent from 28 to 40 percent of total emissions, depending on the level of control technology applied. The natural gas industry is the second most significant source, ranging from about 20 to 33 percent of all emissions.

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1. EXECUTIVE SUMMARY

A forecast of oxides of nitrogen emissions for Alberta has been developed for the period 1980 to 2000. The forecast is based on two provincial growth profiles and the application of present, best practicable, and best available technology.

The growth profiles include industrial, commercial, residential, and transportation components. Principal factors are total natural gas production and its consumption in Alberta, population growth, electrical energy production, general industrial growth, passenger car and commercial vehicle growth, and rail locomotive usage. A reasonably optimistic high growth scenario (A) and a more conservative low growth scenario (B) are developed based on an analysis of the above factors. In addition, aspects that may adversely or beneficially impact upon the emission forecast are also considered.

Oxides of nitrogen emission potentials are developed for each growth scenario and through the application of present, best practicable, and best available technology, emission forecasts are developed for the following sectors: natural gas, electric utility, oil sands, other industries, transportation, and residential/commercial. The consolidated forecasts for the province are also prepared.

1.1 GROWTH PROFILES

The growth profiles consider population and transportation trends, electric energy requirements, all industrial sectors, and the natural gas industry. Consideration of the natural gas industry includes the forecast demand for marketable gas and the end-use consumers of natural gas within Alberta. End-use consumers include the residential, commercial, electrical generation, oil sands, and other industrial sectors.

The growth scenarios are summarized in the following sections.

1.1.1 Scenario A

1.1.1.1 Population. Alberta's population is forecast to increase to 3.8 million by 2000. This represents an annual growth rate of about 2.9 percent.

1.1.1.2 Transportation. Passenger car and commercial vehicle populations are projected to grow at annual rates of 3.8 and 4.1 percent, respectively, and fuel oil consumption by railways is projected to increase by 3 percent per annum.

1.1.1.3 Electrical Generation. Total electrical energy requirements are projected to increase steadily from 21 900 GW h in 1980 to about 63 222 GW h by 2000. This projection represents an increase of approximately 190 percent.

1.1.1.4 Industrial Growth. Oil sands production capacity is forecast to increase to 84 000 m³/d by 2000 from a present level of 34 000 m³/d.

The growth of other industries expressed in terms of natural gas consumption is projected to be about 4.6 percent per annum. This includes the natural gas consumption by both existing and new plants for fuel and feedstock.

1.1.1.5 Natural Gas. The demand forecast for natural gas includes residential, commercial, and industrial needs in Alberta, deliveries to other provinces, current and recently approved exports to the US, and increased shipments to eastern Canada. Total marketable gas deliveries are forecast to peak at 3661 PJ in 1986, drop to about 2990 PJ in 1991 and 1992, and then increase slowly to 3268 PJ by 2000. These figures are to be compared with 1980 deliveries of 2209 PJ.

1.1.2 Scenario B

1.1.2.1 Population. Alberta's population is forecast to grow at an annual rate of 1.8 percent to about 3.0 million by 2000.

1.1.2.2. Transportation. Annual growth rates of 2.6 and 3.0 percent, respectively, are projected for passenger cars and commercial vehicles. Fuel oil consumption for rail locomotives is projected to increase at an annual rate of 3 percent.

1.1.2.3 Electrical Generation. For this reduced growth scenario, an electrical generation requirement of 52 088 GW h in 2000 is projected. This is an increase of about 140 percent over 1980 requirements.

1.1.2.4 Industrial Growth. No increase in oil sands production capacity is forecast for this scenario and it is assumed that existing plants reach their maximum capacity by 1985.

Other industrial sectors, in terms of natural gas consumption for fuel and feedstock, are forecast to grow at 4.6 percent per year.

1.1.2.5 Natural Gas. Lower Alberta consumption due to reduced industrial activity (oil sands) and population (residential and commercial consumption), coupled with reduced exports to the US and no development of the eastern Canadian market, result in a low marketable gas requirements forecast. Deliveries are forecast to peak at 3031 PJ in 1986, decrease to 2226 PJ in 1992, and then increase slowly to 2641 PJ by 2000.

1.2 OXIDES OF NITROGEN EMISSIONS

Emission forecasts for each sector are based on detailed analysis of the source of emissions and the technology that may be used to reduce the formation or emission of oxides of nitrogen. Emission potential is characterized by fuel type, combustion chamber

design, and combustion conditions. Emission control technology includes fuel modification, combustion chamber design changes, and combustion condition manipulation plus post-combustion control primarily using catalytic devices. The latter are generally added to the system after all other modifications to combustion chamber design and operating conditions have been made.

1.2.1 Emission Factors

Essentially all oxides of nitrogen emissions in Alberta are the result of the combustion of a fossil fuel. Each fuel consuming device is characterized by an emission factor. These factors are summarized for residential, commercial, and industrial operations in Table 1 and for the transportation sector in Table 2. In each case, factors for present (PT), best practicable (BPT), and best available technology (BAT) are presented.

1.2.2 Emission Forecasts

The consolidated emission forecasts for 1982 to 2000 are presented in Figure 1. Historical estimates from 1974 to 1981 are also presented.

Oxides of nitrogen emission levels for 1980 are estimated at 931 t/d and these are forecast to increase to 1833 t/d for Scenario A and 1502 t/d for Scenario B by 2000. In the mid 1980s, a slight peak associated with high marketable gas deliveries is predicted. Increases after this peak are due primarily to growth in the transportation and electric utility sectors.

The application of best practicable technology to all sectors starting in 1985 results in either a negligible increase (Scenario A) or a 15 percent decrease (Scenario B) in total emissions by 2000 as compared to 1980 levels. However, a small peak from 1984 to 1986 cannot be avoided even if increased efforts are taken to reduce emissions in the immediate future.

Best available technology has the potential to provide a substantial decrease in total emissions and, if implemented starting in 1990, could reduce emissions by 50 to 60 percent by 2000. In most

Table 1. Summary of NO_x emission factors used for stationary sources.^a

	PT (ng/J)	BPT (ng/J)	BAT (ng/J)
Natural Gas Industry			
Heaters & Boilers	99	64	40
Gas Turbines	126	75	38
Reciprocating Engines	1481	889	296
Electric Utilities			
Coal-fired Boilers	184	120	37
Gas-fired (large) Boilers	113	107	12
Gas-fired (small) Boilers	257	257	257
Oil Sands			
Gas-fired Power Boilers	257	129	26
Gas-fired Steam Boilers	99	64	10
Coke-fired Power Boilers	184	120	37
Other Industries			
Gas-fired (medium-size) Boilers	257	129	103
Residential Sector			
Gas-fired Boilers	34	20	10
Propane-fired Boilers	32	19	10
Oil-fired Boilers	58	46	17
Commercial Sector			
Gas-fired Boilers	51	33	20

^a as NO₂

Table 2. Summary of NO_x emission factors used for mobile sources.^a

	PT	BPT	BAT
	<u>g/km</u>	<u>g/km</u>	<u>g/km</u>
Passenger Cars	1.9	0.6	0.2
Commercial Vehicles			
Light Duty Trucks	1.9	0.6	0.2
Medium Duty Trucks	1.9	0.6	0.4
Heavy Duty (Gasoline) Trucks	5.8	3.0	1.2
Heavy Duty (Diesel) Trucks	14.2	3.3	3.3
	<u>kg/10³L</u>	<u>kg/10³L</u>	<u>kg/10³L</u>
Railway Diesel Locomotives	44	35	22

^a
as NO₂

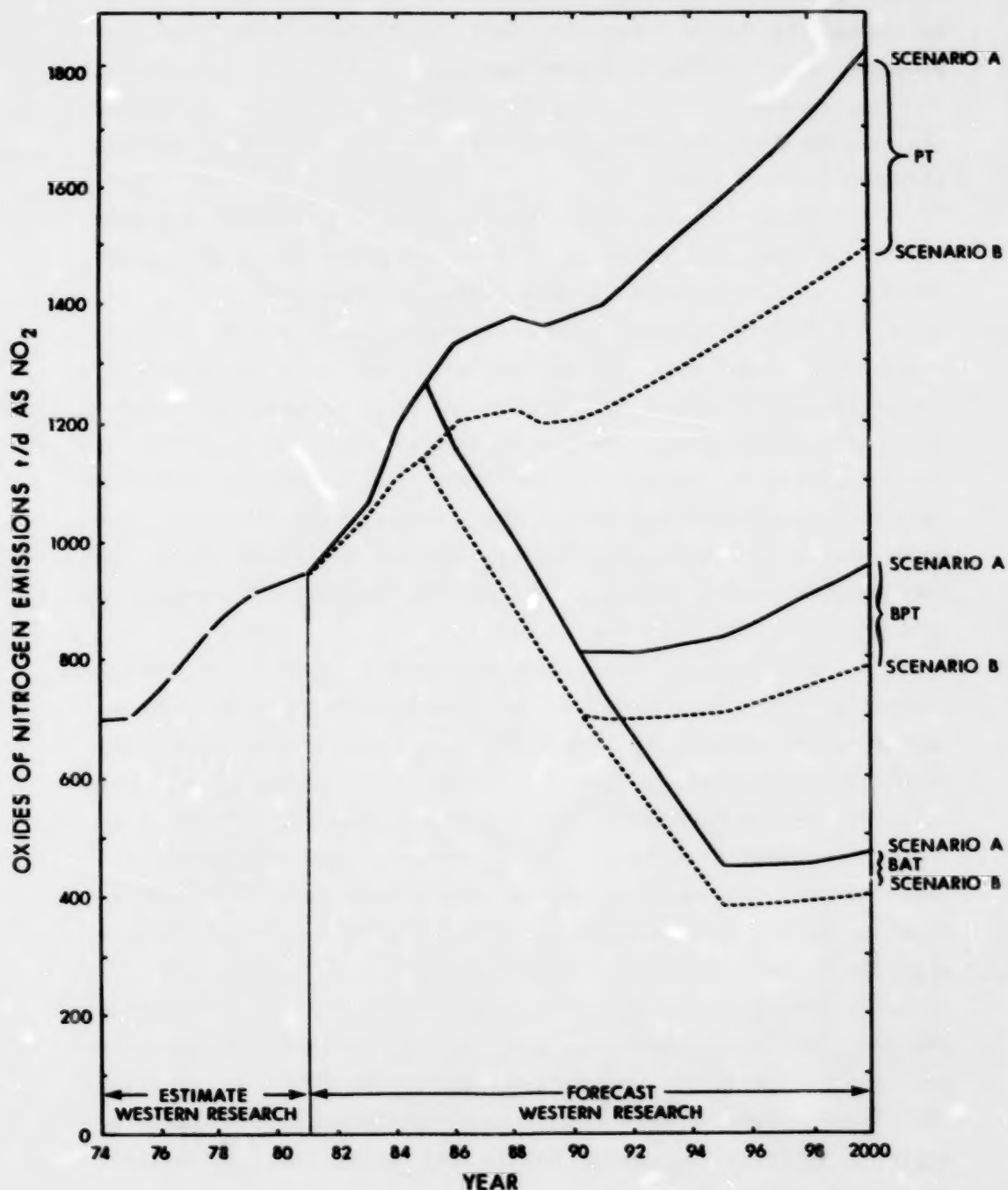


Figure 1. Total Alberta oxides of nitrogen emissions forecast 1980 to 2000.

cases, the measures taken for best available technology would be additional to those taken for best practicable technology. In essence, best available technology (for industrial and utility sources) consists of the application of best practicable technology starting in 1985 and the application of catalytic control devices starting in about 1990.

Figure 2 summarizes the relative contribution of each industry to the total emissions in Alberta in 1980 and in 2000 using present, best practicable, and best available technology.

At present, four sectors (natural gas, electric utility, transportation, and other industries) represent about 95 percent of the provincial emissions. Oil sands and residential/commercial sectors are minor contributors. The single biggest source of emissions is the transportation sector (37 percent), with commercial vehicles contributing about 70 percent of the transportation emissions. The major source of emissions from the natural gas industry is the reciprocating engine, which is responsible for about 90 percent of this industry's total emissions.

Moving to the year 2000, with the application of present technology the contribution of the transportation sector remains approximately constant at 37 percent, while that of the natural gas sector drops from 33 to 25 percent. The contribution of electric utilities increases from 12 to 19 percent, and that of the other industries remains unchanged at 12 percent. The contribution of other sectors changes slightly, and represents about 7 percent of total emissions throughout the forecast period. Relative rank is essentially the same for scenarios A and B.

The most significant impacts of applying best practicable and best available technology occur in the natural gas, electric utility, transportation, and other industries sectors. On a provincial basis, relatively insignificant gains are experienced by applying improved technology to the oil sands, and residential/commercial sectors.

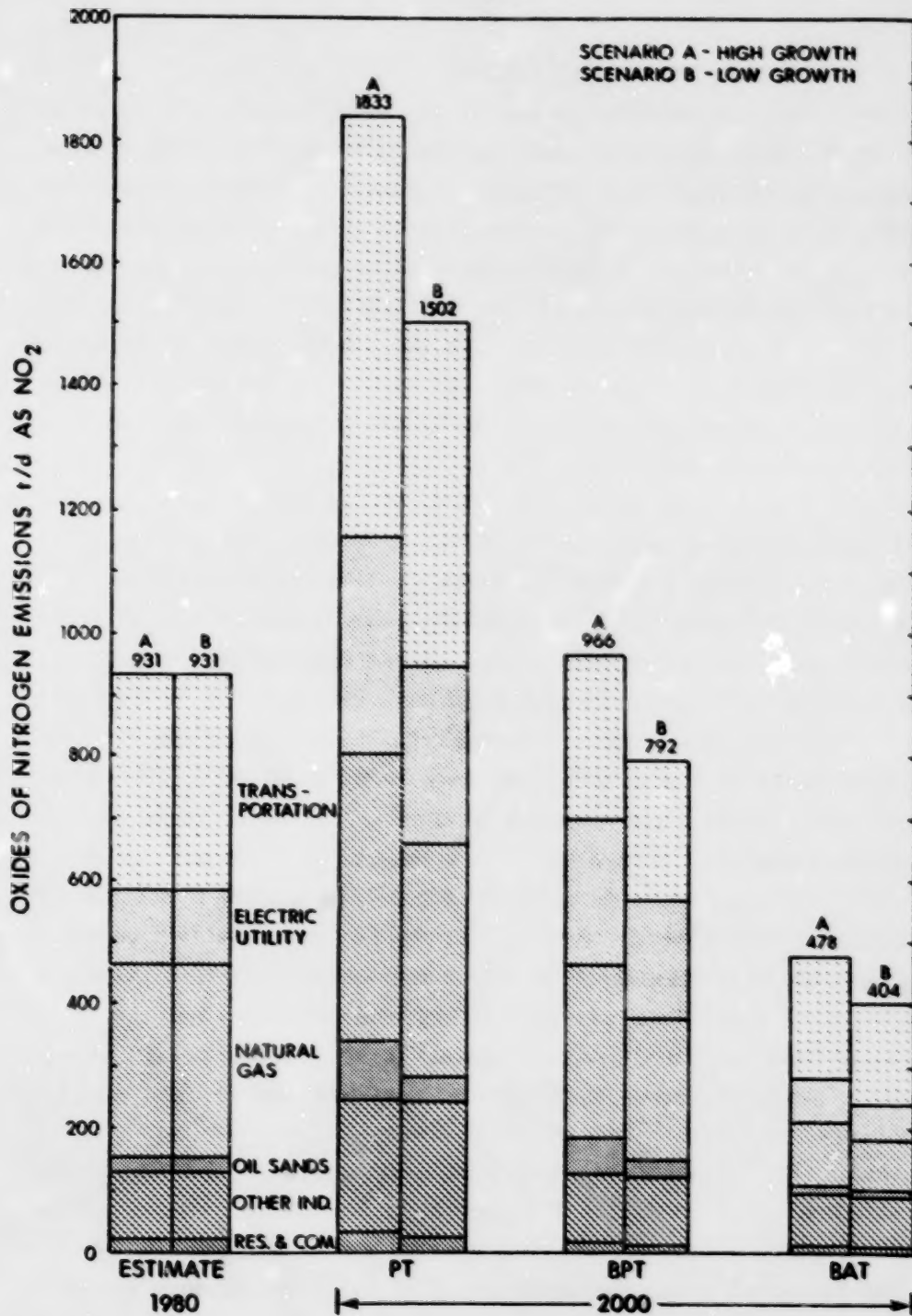


Figure 2. Oxides of nitrogen source and emission estimate for 1980 to 2000.

1.3 SUMMARY AND RECOMMENDATIONS

Oxides of nitrogen emissions can be expected to increase by 60 to 100 percent by the year 2000 compared to 1980, unless improved technology is used in fuel combustion processes. If best practicable technology is applied, it is reasonable to expect no increase or a modest decrease in emissions, depending on the actual level of growth experienced by the province.

Should substantially reduced oxides of nitrogen be required, best available technology has the potential to reduce total forecast emissions in 2000 to about 50 to 60 percent of 1980 levels.

Four sectors are the primary emitters of oxides of nitrogen. Ranked by magnitude for 1980, they are: transportation (37 percent); natural gas (33 percent); electric utilities (12 percent); and other industries (12 percent). Over the forecast period, this ranking will be maintained but natural gas will drop to 25 percent and electric utilities will increase to 19 percent.

Research efforts to reduce emissions should be directed towards reciprocating engines and large utility boilers. The former category includes all transportation vehicles and reciprocating engines commonly used to drive compressors in the gas industry.

A need exists to more accurately document sources of oxides of nitrogen in Alberta so that representative emission factors and characteristics of operations in the Alberta climate can be established. This can be done by standardizing and upgrading regular emission test programs so as to record and relate energy input, emission output, and source type and design, and ambient conditions.

2. INTRODUCTION

This study was commissioned by Alberta Environment, Research Management Division with the objective of establishing a forecast of oxides of nitrogen emissions to the year 2000. The study follows very closely the format and industrial growth forecast prepared in a similar study for sulphur dioxide emissions.

The objectives of the oxides of nitrogen emission forecast are summarized as follows:

1. Develop two growth scenarios, in consultation with Alberta Environment, for the industrial, transportation, and heating fuel combustion sources emitting NO_x up to the year 2000. The contributing sources are defined as: electric utility power plants; residential, commercial, and industrial heating; gasoline and diesel motor vehicles and railways; and the natural gas processing industry.
2. Estimate NO_x emissions to the year 2000 considering the present technology employed by industry for pollution abatement using the two growth scenarios.
3. Estimate NO_x emissions to the year 2000 considering the best practicable technology for pollution abatement using the two growth scenarios.
4. Estimate NO_x emissions to the year 2000 considering the best available technology for pollution abatement using the two growth scenarios.
5. Develop emission control options to maintain a zero growth of NO_x emissions to the year 2000.

Two industrial growth profiles were developed for the sulphur dioxide forecast and these are also used in this study. Because sources of oxides of nitrogen are considerably more widespread and complex than are those for sulphur dioxide, the industrial growth profiles had to be reassessed in certain instances and expanded in others. No attempt was made to revise or update the industrial growth profiles that had been developed previously.

3. GROWTH FORECASTS

Oxides of nitrogen emissions forecasts for industrial, transportation, and heating fuel combustion sources require growth forecasts that include industrial growth and population increases. The latter serves as a basis for residential, commercial, and transportation sources of emissions.

Industrial growth in Alberta has been analysed in detail to produce a forecast of sulphur dioxide emissions (Colley and Poon 1982), and, except for the distribution of marketable gas demands within the province of Alberta, it is the referent for the present study and relevant tables and figures are included in the following pages. For marketable gas consumption in Alberta the forecast was re-examined and, although the total demand remains unchanged, the distribution as to its consumption as fuel or as feedstock, and as to the sector of the Alberta economy is provided herein.

3.1 POPULATION GROWTH PROJECTIONS

Two population growth projections were adopted from the population projections provided by Alberta Treasury (1979). They are used directly in the forecasts of natural gas consumption, electric energy requirements, and growth of motor vehicles, and thereby impact on the oxides of nitrogen emission forecast.

The Bureau of Statistics developed nine growth projections that are based on combining each of three fertility assumptions with each of three net migration assumptions. The assumptions are as follows:

1. Fertility Assumptions.

Low fertility rate continues to decline until it reaches a level of 1.9 births per woman in 1985.

Medium fertility continues at the present rate of 2.1 births per woman.

High fertility rate increases to 2.3 births per woman by 1985.

The 1985 fertility rates continue to 2006 for all three assumptions.

2. Net Migration Assumptions.

Set A: Net migration to Alberta will continue to increase, levelling off in 1987 and 1988 at 46 400 persons per year.

Set B: Net migration to Alberta will decline, levelling off at 19 000 persons per year in 1986 and 1987.

Set C: Using a moderate base level of migration, the migration additions produced by the coming on-stream of an oil sands plant and a gas pipeline are assumed. The projected net migration is 34 000 persons by 1987 and 1988.

The assumptions on fertility and net migration are combined to produce the following series of projections:

Series 1: Low Fertility and Migration Set C

Series 2: Low Fertility and Migration Set A

Series 3: Low Fertility and Migration Set B

Series 4: Medium Fertility and Migration Set C

Series 5: Medium Fertility and Migration Set A

Series 6: Medium Fertility and Migration Set B

Series 7: High Fertility and Migration Set C

Series 8: High Fertility and Migration Set A

Series 9: High Fertility and Migration Set B

Scenario A, high growth, assumes the population projections in Series 8 which assumes rising fertility and increasing migration to Alberta, but not the additional population influx that an oil sands plant and a major northern pipeline would bring. The population in 2000 is forecast to be 3.8 million.

Series 6 projections are assumed for Scenario B, low growth. They assume the continuance of the present rate of fertility and a decline in net migration to Alberta. The population is forecast to be 3.0 million in 2000.

3.2 TRANSPORTATION

Motor vehicles can generally be classified into two types, private passenger cars and commercial vehicles, according to their registration. To develop the growth profiles of motor vehicles in Alberta, the growth pattern of these two types of motor vehicles was examined.

3.2.1 Private Passenger Cars

Data regarding private passenger car registration were obtained from the Alberta Motor Vehicles Division (letters dated 1982 October 1 and November 25 from A.D. Fry and P. Wong, Motor Vehicles Division, Edmonton, Alberta) and data regarding the population in Alberta were obtained from the Alberta Treasury (1980). From these two sets of data, the passenger car ownership ratio (the ratio of the number of passenger cars to the total population) was calculated and analysed to assist in predicting the growth of passenger cars in Alberta.

Analysis of the passenger car ownership ratio indicated that the ratio had grown from 0.27 in 1961 to 0.53 in 1981, an annual rate of 3.4 percent. If this growth rate is maintained during the forecast period, the passenger car ownership ratio would grow to 1.06 (more than 1 car per person in Alberta) by the year 2000. This ratio was considered to be unrealistically high.

Further analysis of the passenger car ownership ratio indicated that if the population in Alberta between the age of 15 to 64 was assumed to have one car per person, the passenger car ownership ratio would stabilize at 0.68 throughout the forecast period; this was assumed to be the saturation level.

It was difficult to forecast with certainty the rate of growth of the passenger car ownership ratio and, thus, the rate of growth of passenger cars in Alberta during the forecast period. Four possibilities were examined:

1. The passenger car ownership ratio was assumed to stabilize at the present level of 0.53 during the forecast period. This ratio, together with the low

population projection, was used to forecast the growth of passenger cars in Alberta.

2. The passenger car ownership ratio was assumed to grow at an annual rate of 1 percent during the forecast period. This, together with the low population projection, was used to forecast the growth of passenger cars in Alberta.
3. The passenger car ownership ratio was assumed to grow at an annual rate of 1 percent during the forecast period. This, together with the high population projection, was used to forecast the growth of passenger cars in Alberta.
4. The passenger car ownership ratio was assumed to grow linearly to the saturation level of 0.68 by the year 2000. This, together with the high population projection, was used to forecast the growth of passenger cars in Alberta.

These four possibilities are summarized in Table 3. Figure 3 outlines the four growth profiles in graphical form. The lowest forecast represents an annual growth rate of 1.8 percent for passenger cars in Alberta during the forecast period. The intermediate or probable range forecasts represent growth rates of 2.6 percent and 3.8 percent, respectively. The highest forecast represents an annual growth rate of 4.2 percent.

For the purpose of this study, it was assumed that the numbers of passenger cars would grow at the rate of the probable range forecasts; hence, the 2.6 percent and 3.8 percent projections were chosen as low growth (Scenario B) and high growth (Scenario A).

3.2.2 Commercial Vehicles

Data regarding commercial vehicle registration were obtained from the Alberta Motor Vehicles Division. Together with the population data delineated in the Alberta Statistical Review Annual (1980), they were used to calculate the commercial vehicle

Table 3. Passenger car population forecast.

Year	Low Variation	Scenario B	Scenario A	High Variation
1980 ^a	1 139 800	1 139 800	1 139 800	1 139 800
1981 ^a	1 204 340	1 204 340	1 204 340	1 204 340
1982	1 222 180	1 234 400	1 234 400	1 238 320
1983	1 235 960	1 260 680	1 282 840	1 293 280
1984	1 241 210	1 286 690	1 331 450	1 348 770
1985	1 262 990	1 313 510	1 380 760	1 405 310
1986	1 274 800	1 338 600	1 431 700	1 467 300
1987	1 301 500	1 379 600	1 493 800	1 538 000
1988	1 327 500	1 420 400	1 557 600	1 610 600
1989	1 353 100	1 461 400	1 632 700	1 697 500
1990	1 378 400	1 502 500	1 688 100	1 760 600
1991	1 403 400	1 543 800	1 754 900	1 838 000
1992	1 428 000	1 585 100	1 822 500	1 916 700
1993	1 452 100	1 626 400	1 891 000	1 996 500
1994	1 475 800	1 667 700	1 960 300	2 077 800
1995	1 499 200	1 709 100	2 030 300	2 160 100
1996	1 522 300	1 750 700	2 101 400	2 244 200
1997	1 545 100	1 792 400	2 173 500	2 329 800
1998	1 567 800	1 834 500	2 246 700	2 420 700
1999	1 599 500	1 876 800	2 321 100	2 505 600
2000	1 613 000	1 919 600	2 396 800	2 596 400

^a Actual data, Alberta Motor Vehicle Division revised by Western Research

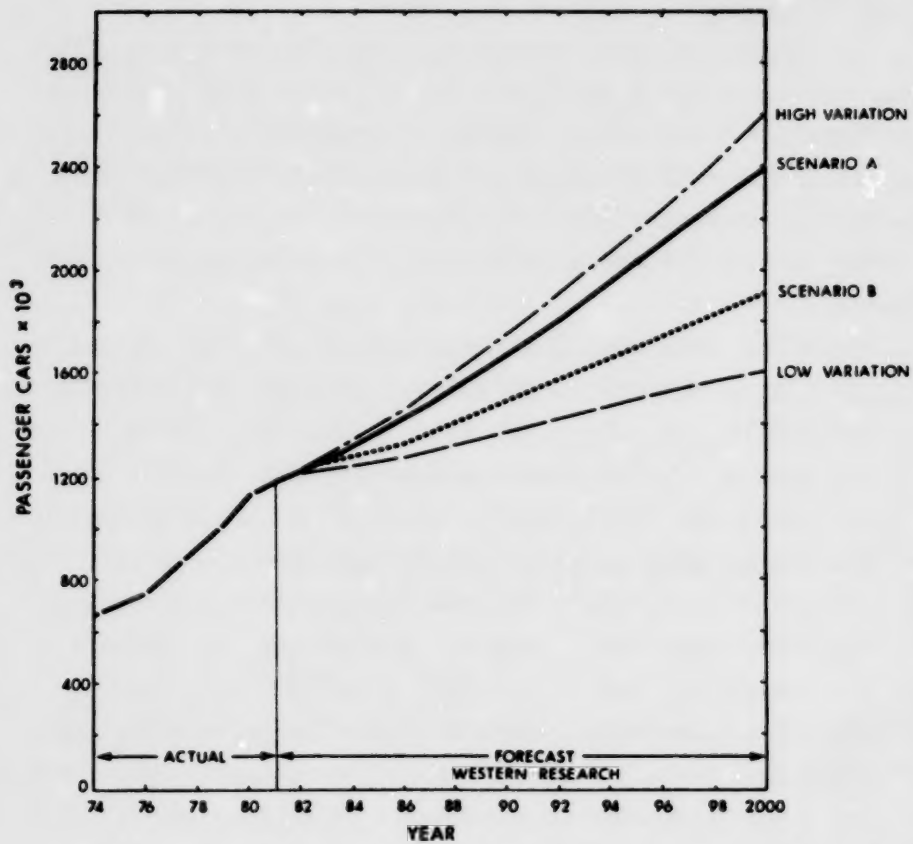


Figure 3. Population growth of passenger cars.

ownership ratio (the ratio between the total number of commercial vehicles and total population in Alberta). The commercial vehicle ownership ratio and the population projections were used to forecast the growth of commercial vehicles in Alberta.

Analysis of the commercial vehicle ownership ratio indicates the ratio had grown from 0.11 in 1961 to 0.22 in 1981, at an annual rate of 3.5 percent. Again, it was difficult to forecast with certainty the rate of growth of the commercial vehicle ownership ratio and, thus, the growth in numbers of commercial vehicles in Alberta during the forecast period. Four projections were developed:

1. The commercial vehicle ownership ratio was assumed to stabilize at the 1979 level of 0.22. This, together with the low population projection, was used to forecast the growth of commercial vehicles.
2. The commercial vehicle ownership ratio was assumed to grow at an annual rate of approximately 1 percent. This, together with the low population projection, was used to forecast the growth of commercial vehicles.
3. The commercial vehicles ownership ratio was assumed to grow at an annual rate of approximately 1 percent during the forecast period. This, together with the high population projection, was used to forecast the growth of commercial vehicles.
4. The commercial vehicle ownership ratio was assumed to grow at the same rate as experienced for the past twenty years (an annual rate of approximately 2.3 percent). This, together with the high population projection, was used to forecast the growth of commercial vehicles.

The four projections are summarized in Table 4 and outlined in Figure 4. The lowest forecast exhibits an average annual growth rate of 1.9 percent. The middle two are intermediate or probable range forecasts with annual growth rates of 3.0 percent and

Table 4. Commercial vehicle population forecast.

Year	Low Variation	Scenario B	Scenario A	High Variation
1980 ^a	463 000	463 000	463 000	463 000
1981 ^a	473 000	473 000	473 000	473 000
1982	509 230	515 500	515 500	520 000
1983	515 840	536 820	546 250	566 510
1984	521 380	548 010	567 090	578 570
1985	527 090	559 490	591 430	612 840
1986	532 250	570 750	610 480	641 880
1987	543 400	588 360	637 050	679 600
1988	554 240	606 110	664 620	718 150
1989	564 950	623 940	697 060	763 830
1990	565 520	642 120	721 450	800 660
1991	585 940	660 370	750 690	843 140
1992	596 200	678 410	780 020	886 620
1993	606 270	696 990	810 380	931 150
1994	616 180	715 340	840 820	876 690
1995	625 930	734 020	871 970	1 023 240
1996	635 570	752 520	903 270	1 070 880
1997	645 110	771 680	935 760	1 120 000
1998	654 600	790 730	968 410	1 169 920
1999	664 040	810 540	1 002 400	1 221 070
2000	673 470	830 260	1 036 670	1 273 500

^a Actual data, Alberta Motor Vehicle Division revised by Western Research

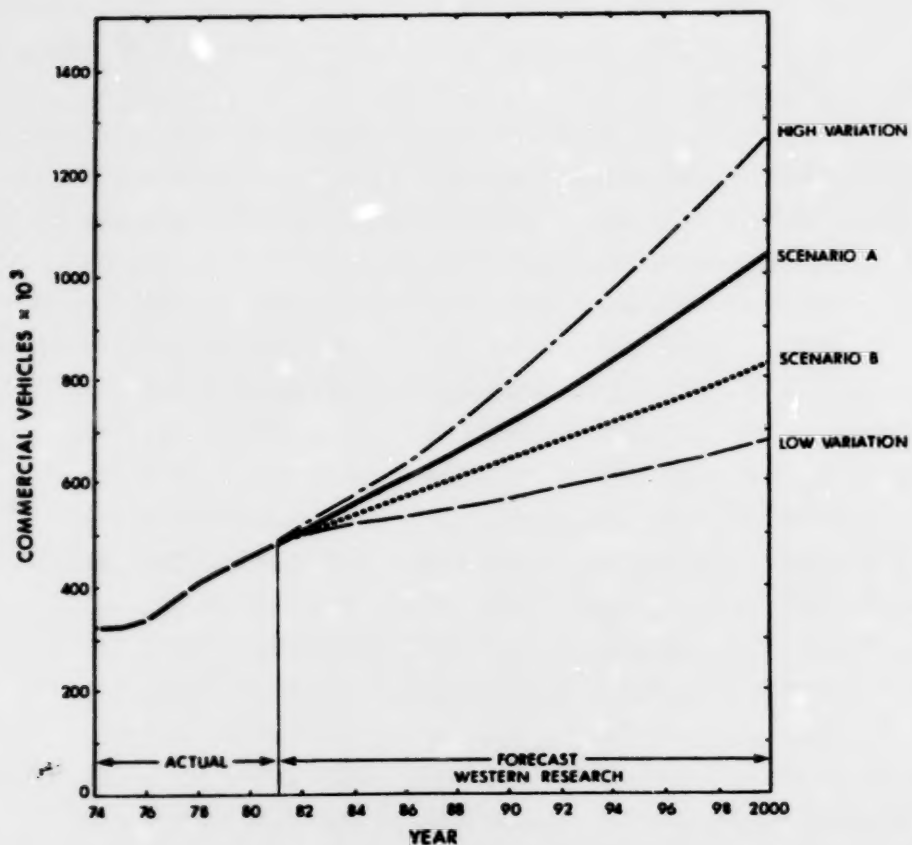


Figure 4. Population growth of commercial vehicles.

4.1 percent, respectively. The highest forecast shows an annual growth rate of 5.2 percent.

For this study, it was assumed that the number of commercial vehicles would grow at the rates of the probable range forecasts; hence, the 3.0 percent and 4.1 percent forecasts were chosen to represent Scenario B and Scenario A, respectively.

3.2.3 Railways

Historical data concerning diesel fuel oil consumption by railway locomotives were obtained from the Fuel Oil Tax Branch of Alberta Treasury (1983 January 11, telephone conversation with D. Moll, Alberta Treasury, Fuel Oil Tax Branch). A forecast of the diesel fuel oil consumption by railways in Alberta was made based on the historical growth trend. No electrification of rail lines is assumed during the forecast period.

Table 5 presents the forecast of the diesel fuel oil consumption in Alberta. It is expected to grow at an annual rate of 3 percent.

3.3 ELECTRIC UTILITY GROWTH

Alberta electric energy requirements from 1980 to 2000 are presented in Table 6 and Figure 5 (Colley and Poon 1982). These estimates are based on scenario A and B industrial growth and population forecasts and include the case where all future requirements are sourced by coal, as well as the case where a major non-thermal source of power is developed.

3.4 INDUSTRIAL GROWTH PROFILE

Industrial growth relevant to oxides of nitrogen emissions is examined and expressed in terms of forecast demands for marketable gas as a fuel and as raw material. Included are demands of present and future oil sands plants, electric utilities, various other industries, residential and commercial sectors, and those of the natural gas industry itself. These demands are examined in detail in the following sections.

Table 5. Railways diesel fuel oil consumption forecast.

Year	Diesel Consumption (10 ⁶ L)
1980 ^a	304
1981 ^a	317
1982	330
1983	342
1984	355
1985	368
1986	380
1987	393
1988	405
1989	420
1990	432
1991	445
1992	457
1993	470
1994	483
1995	495
1996	508
1997	521
1998	534
1999	546
2000	559

^a Actual data from Alberta Treasury (1983).

Table 6. Supply of electric energy requirements by source type.

	Hydro (GW h)	Gas ^b (GW h)	Grid (GW h)	Coal (GW h)	Total (GW h)
Scenario A					
Case 1 - All Coal					
1980 ^a	1 699	3 728	0	16 473	21 900
1985	1 780	4 380	6	27 334	33 500
1990	1 780	3 724	10	36 108	41 622
1995	1 401	3 547	36	46 655	51 639
2000	1 330	3 833	49	58 010	63 222
Case 2 - Hydro Plus Western Grid					
1980 ^a	1 699	3 728	0	16 473	21 900
1985	1 780	4 380	6	27 334	33 500
1990	1 780	4 181	50	35 611	41 622
1995	5 715	3 760	4 421	37 743	51 639
2000	5 644	2 364	4 386	50 828	63 222
Scenario B					
Case 1 - All Coal					
1980 ^a	1 699	3 728	0	16 473	21 900
1985	1 780	4 380	6	24 658	30 824
1990	1 780	3 724	10	32 126	37 640
1995	1 401	3 547	36	39 848	44 832
2000	1 330	3 833	49	46 876	52 088
Case 2 - Hydro Plus Western Grid					
1980 ^a	1 699	3 728	0	16 473	21 900
1985	1 780	4 380	6	24 658	30 824
1990	1 780	4 181	50	31 629	37 640
1995	5 715	3 760	4 421	30 936	44 832
2000	5 644	2 364	4 386	39 694	52 088

^a Actual data from ERCB (1982a).

^b For electrical energy supplied by gas, a constant value of 260 GW h per year was assumed to be supplied by small gas-fired generators for the entire forecast period.

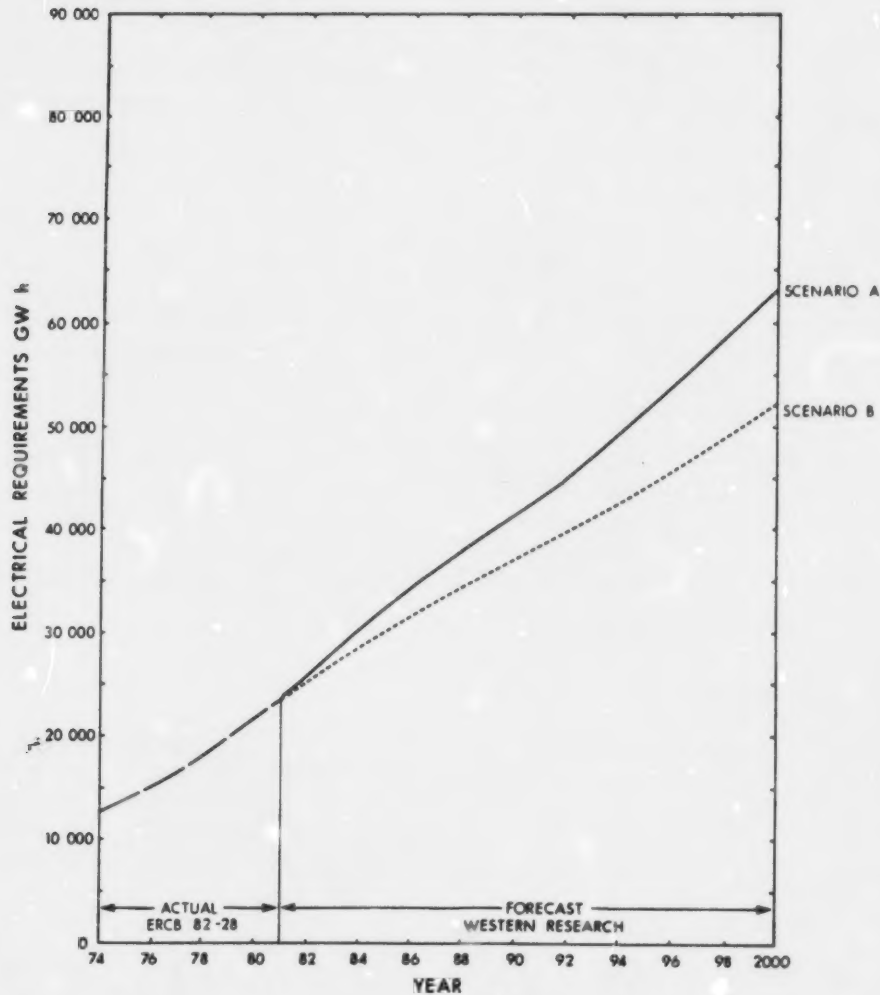


Figure 5. Electrical energy requirements forecast. Figures for actual requirements prior to 1981 were obtained from ERCB Report 82-28 (1982).

3.4.1 Residential and Commercial Gas Requirements

The forecasts of natural gas requirements for the residential and commercial sectors delineated in the 1981 EUPC submission are adopted as the basis of this forecast. Adjustments are made to reflect growth scenarios A and B.

For the residential sector in Scenario A, the natural gas requirements are expected to grow from 99 PJ/a in 1980 to 151 PJ/a in 2000, an annual rate of 2.2 percent. In Scenario B, the natural gas requirements are expected to grow from 99 PJ/a in 1980 to 121 PJ/a in 2000, an annual rate of 1 percent.

For Scenario A of the commercial sector, natural gas requirements are expected to grow from 91 PJ/a in 1980 to 135 PJ/a in 2000, an annual rate of 2 percent. In Scenario B, the natural gas requirements are expected to grow from 91 PJ/a in 1980 to 108 PJ/a in 2000, an annual rate of 1 percent.

3.4.2 Electric Generation Gas Requirements

Forecasts of electric energy supplied by natural gas are adopted from EUPC 1981 and are listed in Table 6. Data regarding thermal efficiencies of gas-fired power plants are obtained from the ERCB Report number 82-28. Calculations based on the electric energy forecasts and the thermal efficiencies indicate that the natural gas requirements for the electric generation industry in Alberta will remain relatively unchanged at the present level of about 50 PJ/a during the forecast period.

3.4.3 Oil Sands Gas Requirements

Alberta synthetic crude oil production forecasts are delineated in Figure 6 (Colley and Poon 1982). Actual consumption of natural gas as fuel and feedstock for the Suncor and Syncrude plants was obtained from the ERCB (1983 January 6 meeting with Thorn Walden and Richard Houlihan of the ERCB, Calgary, Alberta), and design data for the natural gas consumption for future in-situ and mining plants were obtained from ERCB reports (ERCB 73-N-OG, 73-K-HE-OG, 79-A, 79-E, 79-H, and 81-C). The consumption data and

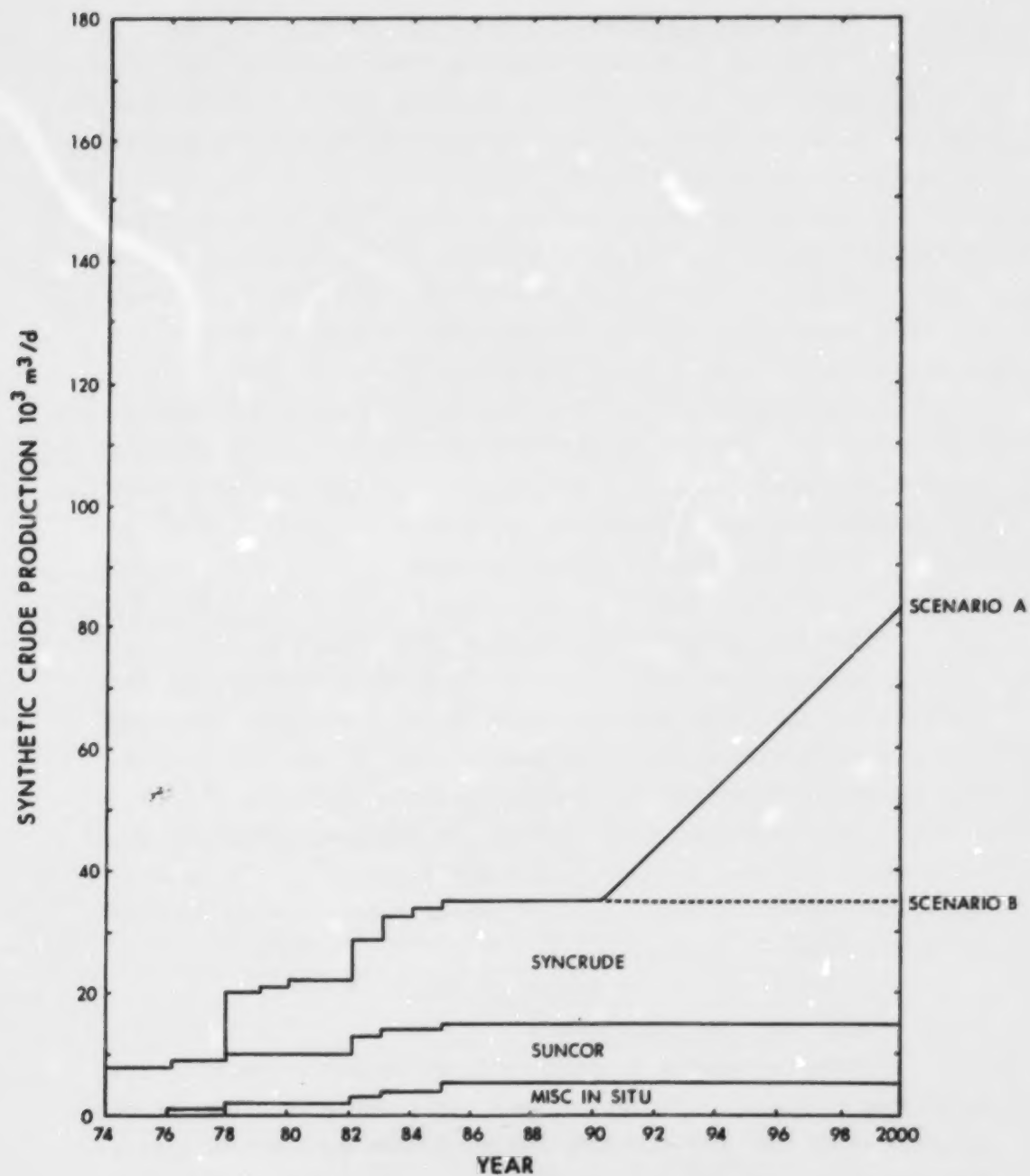


Figure 6. Oil sands production forecast.

the growth forecasts were used to estimate the total natural gas requirements for the oil sands industry.

In Scenario A, fuel requirements are expected to grow from 31 PJ/a in 1980 to 110 PJ/a in 2000. Feedstock requirements are expected to grow from 15 PJ/a in 1980 to 65 PJ/a in 2000.

In Scenario B, fuel requirements are expected to grow from 31 PJ/a in 1980 to 58 PJ/a in 1985 and feedstock requirements are expected to grow from 15 PJ/a in 1980 to 24 PJ/a in 1985. The increases in natural gas requirements from 1980 to 1985 are due to the forecast production increase of the Suncor and Syncrude plants. As no future expansions or additions of oil sands plants are considered in Scenario B, the natural gas requirements are expected to remain unchanged until after 2000.

3.4.4 Other Industrial Gas Requirements

Other industrial gas requirements include fuel and feedstock requirements for the petrochemical, fertilizer, refining, and all other industries (except for electric generation and oil sands) in Alberta. Historical data for the total industrial gas requirements were obtained from the ERCB (1982). Analysis of these data and the industrial growth profiles of scenarios A and B indicated that the other industrial requirements would grow from 220 PJ/a in 1980 to 539 PJ/a in 2000, an annual rate of 4.6 percent. Growth profiles for scenarios A and B for the other industries are relatively similar; hence, requirements of natural gas are expected to be similar. Feedstock requirement forecasts for petrochemical, fertilizer, and refining industries delineated in the EUPC (1981) submission are adopted as the basis for the other industrial feedstock requirements, with adjustments made for revised growth rates. For the other industrial category, the difference between the industrial gas requirements and the feedstock requirements is taken as the forecast for the fuel requirements.

Feedstock requirements are expected to grow from 64 PJ/a in 1980 to 234 PJ/a in 2000 and fuel requirements are expected to grow from 156 PJ/a in 1980 to 305 PJ/a in 2000.

Tables 7 and 8 summarize the natural gas requirements for the residential and commercial sectors, and for the electric generation, oil sands, and other industries for scenarios A and B, respectively.

3.4.5 Natural Gas Industry

Total emissions of oxides of nitrogen are related to the total marketable gas delivery forecast which combines Alberta's requirements, deliveries to other provinces, and exports to the US. These data are presented in Table 9 and Figure 7.

Table 7. Scenario A: Alberta natural gas requirements forecast.

Year	Residential (PJ)	Commercial (PJ)	Electrical Generation (PJ)	Oil Sands Feedstock (PJ)	Fuel (PJ)	Other Industrial Feedstock (PJ)	Fuel (PJ)	Total ^d Requirements (PJ)
1980	99 ^a	91 ^a	48 ^a	15 ^c	31 ^c	64 ^c	156 ^c	504 ^a
1981	104 ^b	84 ^b	43 ^b	16 ^c	33 ^c	76 ^c	160 ^c	516
1982	114	77	52	21	42	81	158	545
1983	118	80	53	23	51	97	160	582
1984	122	81	55	24	53	113	181	629
1985	119	82	57	24	58	129	182	651
1986	121	84	55	24	58	145	202	689
1987	129	90	53	24	58	160	223	737
1988	132	93	52	24	58	176	242	777
1989	134	95	50	24	58	192	253	806
1990	135	97	48	24	58	207	246	815
1991	132	96	48	28	63	209	255	831
1992	131	97	47	32	68	210	273	858
1993	137	104	47	37	74	214	270	883
1994	139	108	46	41	78	216	278	906
1995	143	113	46	44	84	218	279	928
1996	145	118	47	48	88	223	285	954
1997	149	124	47	53	94	230	286	983
1998	148	126	48	57	99	232	293	1003
1999	149	130	49	61	104	234	299	1026
2000	151	135	50	65	110	234	305	1050

^a Actual data from ERCB (1981)^b Actual data from ERCB (1982b)^c Developed after discussions with ERCB^d Colley and Poon (1982)

Table 8. Scenario B: Alberta natural gas requirements forecast.

Year	Residential (PJ)	Commercial (PJ)	Electrical Generation (PJ)	Oil Sands Feedstock (PJ)	Oil Sands Fuel (PJ)	Other Industries Feedstock (PJ)	Other Industries Fuel (PJ)	Total ^d Requirements (PJ)
1980 ^a	99	91	48	15	31	64	156	504
1981 ^a	104	84	43	16	33	76	160	516 ^b
1982	111	75	52	21	42	81	158	540
1983	114	77	53	23	51	97	160	515
1984	116	77	55	24	53	113	181	619
1985	113	77	51	24	58	129	182	640
1986	113	78	55	24	58	145	202	675
1987	119	83	53	24	58	160	223	720
1988	121	84	52	24	58	176	242	757
1989	120	85	50	24	58	192	253	782
1990	120	86	48	24	58	207	246	789
1991	116	84	48	24	58	209	255	794
1992	114	84	47	24	58	210	273	810
1993	118	89	47	24	58	214	270	820
1994	118	92	46	24	58	216	278	832
1995	120	95	46	24	58	218	279	840
1996	121	98	47	24	58	223	285	856
1997	123	102	47	24	58	230	286	870
1998	121	103	48	24	58	232	293	879
1999	121	105	49	24	58	234	299	890
2000	121	198	50	24	58	234	305	900

^a Actual data from ERCB (1981)^b Actual data from ERCB^c Developed after discussions with ERCB^d Colley and Poon (1982)

Table 9. Total Alberta marketable gas deliveries forecast.

Year	Scenario A (PJ)	Scenario B (PJ)
1980 ^a	2 209	2 209
1981	2 226	2 226
1982	2 352	2 352
1983	2 527	2 527
1984	3 209	2 824
1985	3 546	2 941
1986	3 661	3 031
1987	3 530	2 875
1988	3 411	2 730
1989	3 090	2 386
1990	3 032	2 302
1991	2 990	2 252
1992	2 944	2 226
1993	2 973	2 275
1994	2 975	2 292
1995	3 013	2 348
1996	3 052	2 395
1997	3 107	2 460
1998	3 156	2 517
1999	3 211	2 578
2000	3 268	2 641

^a Actual data from ERCB (1982a).

Source: Colley and Poon (1982)

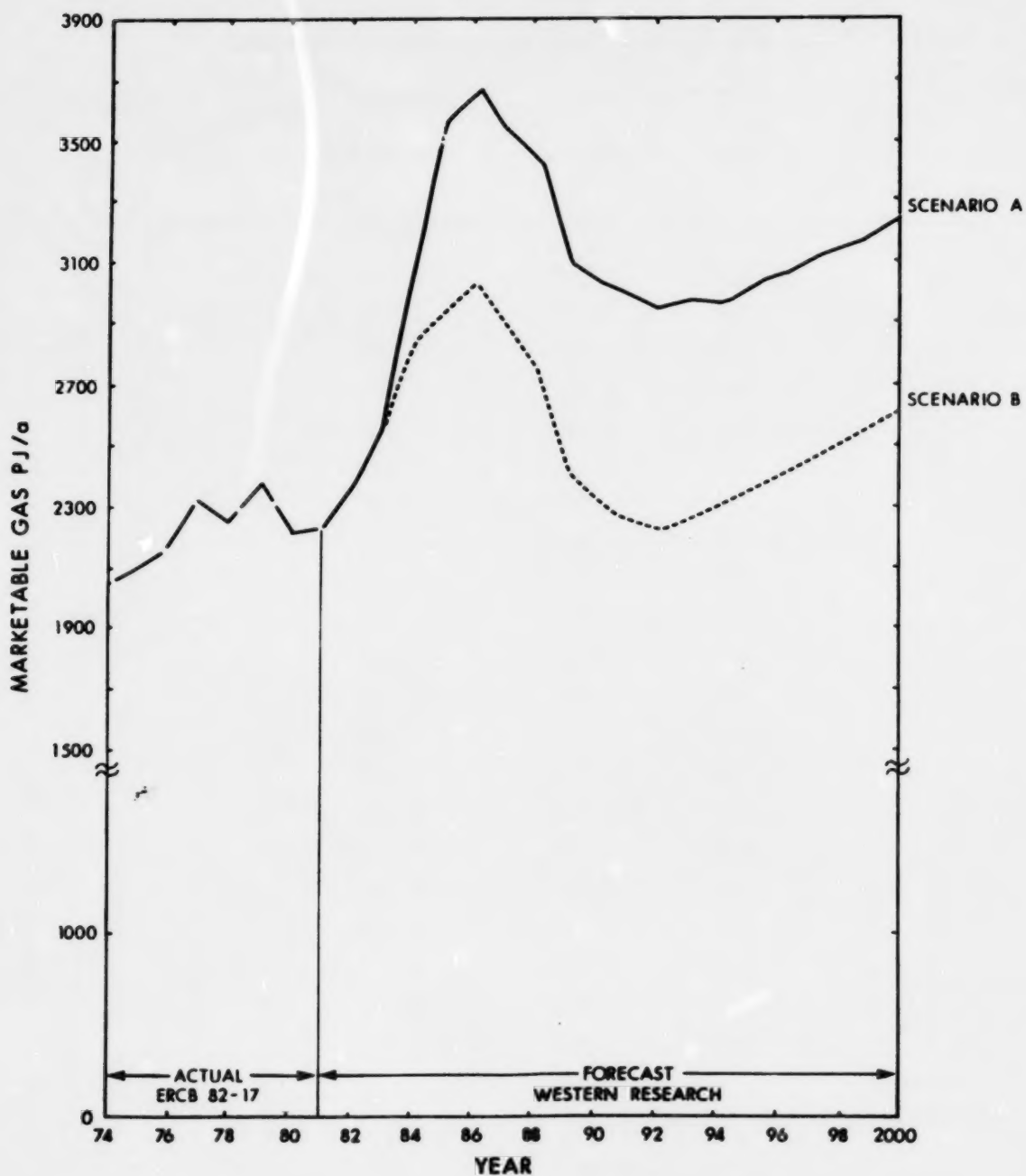


Figure 7. Alberta marketable gas deliveries forecast. Figures for actual deliveries prior to 1981 were obtained from ERCB Report 82-17 (1982).

4. OXIDES OF NITROGEN EMISSIONS FORECAST

This section presents the oxides of nitrogen (NO_x) emissions forecast based on the growth profiles delineated in Section 3. In almost all cases, oxides of nitrogen are emitted as nitric oxide (NO) which is relatively less harmful than other oxides of nitrogen but is important as the main precursor to NO_2 formation in the atmosphere.

All emissions are forecast in terms of their NO_2 equivalent. Two separate mechanisms, thermal NO_x formation and fuel NO_x formation, are responsible for the generation of NO_x during fossil fuel combustion. Thermal NO_x results from the thermal fixation of molecular nitrogen and oxygen in the combustion air, while fuel NO_x derives from the oxidation of organically bound nitrogen in certain fuels such as coal and coke.

In this section, each industry is examined to establish its oxides of nitrogen emission potential over the forecast period by the two mechanisms. Technology for control of NO_x emissions is applied to determine forecast emission. Three classes of technology have been used and are briefly described:

1. Present Technology. Present technology (PT) represents the current industry standard or the current regulatory guideline for control.
2. Best Practicable Technology. Best practicable technology (BPT) represents the application of proven technology that yields the best results having regard for resource conservation, environmental impact, and economics. Best practicable technology should be considered a moving target and constantly reflects the best efforts of engineers and scientists to improve the technical aspects of the control process as well as its economics.
3. Best Available Technology. Best available technology (BAT) represents the application of developing or emerging control technology without regard for economics. In most cases, it is a technology that is

capital- and energy-intensive and is not necessarily proven in Alberta. Normally, best available technology is only applied in response to direct government intervention.

The selection of the emission control potential of each level of technology was based on an evaluation of current literature and contact with selected industry representatives. The time frame for implementation of each level of technology was based primarily on considerations for physically constructing the facilities and was not based on analyses of economic or environmental need.

After each industry is examined individually to determine its forecast emission rate for PT, BPT, and BAT, the findings are consolidated for growth scenarios A and B to give a total emission forecast for Alberta.

4.1 NATURAL GAS INDUSTRY

NO_x emissions associated with the natural gas industry result from the combustion of natural gas as a fuel. In order to forecast emissions, current trends in fuel gas use are established and projected into the future. Estimates of how fuel is used within the industry and of emission factors for each source are combined with total delivery forecasts to determine the overall NO_x emissions.

4.1.1 Fuel Gas Usage

Table 10 summarizes the fuel gas usage by category and end user for the forecast period. Results are given as percentages of total deliveries. For example, 8.80 units of fuel are consumed by the natural gas industry for each 100 units of gas delivered. The six categories (field, gathering, processing, injection, transportation and distribution, and reprocessing) are the steps most raw gas goes through before being delivered.

Table 10. Natural gas industry fuel gas usage as a percentage of total deliveries (1980 to 2000).

Category	End User				Total
	Reciprocating Engines	Gas Turbines	Heaters and Boilers	Incinerators	
Field	0.13	-	1.12	-	1.25
Gathering	1.00	0.05	-	-	1.05
Processing - Sweet Gas	1.14	-	0.61	-	1.75
- Sour Gas	0.72	-	2.34	0.54	3.60
Injection	0.07	0.08	-	-	0.15
Transportation	0.05	0.45	-	-	0.50
Reprocessing	-	0.43	0.07	-	0.50
Total	3.11	1.01	4.14	0.54	8.80

^a with sulphur recovery

Fuel gas usage factors for each category are developed from fuel consumption and total deliveries data contained in the ERCB Oil and Gas Industry, Annual Statistics for the years 1972 to 1981.

Each category is analysed separately to determine the proportion of fuel gas used by reciprocating engines, gas turbines, heaters and boilers, and incinerators.

4.1.1.1 Field. Field fuel is used at oil and gas batteries in the collection and conditioning of raw oil and gas before the resource is sent to the processing plant or pipeline system. From 1972 to 1981, field fuel usage remained relatively constant, ranging from 1.22 to 1.29 percent of total deliveries.

An average field fuel usage of 1.25 percent of total deliveries is used for the forecast period.

To forecast emissions, it is estimated that 90 percent of field fuel is used in heaters and the remaining 10 percent in reciprocating compressor engines (derived from Berlie, Ritter, and Sames 1982).

4.1.1.2 Gathering. Gathering fuel is used to transport the raw gas to the processing plant if processing is required, or, in the case of dry sweet gas, to the pipeline system. Gathering fuel is used exclusively in compressor engines.

In recent years, the fuel gas requirements as a percentage of total deliveries have increased from 0.22 percent in 1972 to 1.05 percent in 1980 and 1981. The increase was due to greater compression requirements as reservoir pressure decreases. Recognizing there is an economic limit to the amount of compression installed, it was assumed that this limit had been reached in recent years. For the forecast period, gathering system fuel usage was assumed constant at 1.05 percent of total deliveries.

Reciprocating engines and gas turbines are estimated to consume 95 percent and 5 percent, respectively, of the fuel gas used for gathering. This split is based on analysing a listing of pipeline compressor stations (Alberta Environment 1982a).

4.1.1.3 Processing Plants. Marketable natural gas is delivered by gas processing plants after impurities and co-products are removed and from sweet, dry gas fields. In recent years, the proportion of marketable gas from sweet, dry gas fields has increased, stabilizing at about 30 percent of the net available marketable gas. In 1980, there were 278 processing plants in Alberta; of these, 45 recover sulphur. Plants with sulphur recovery process about 60 percent of the raw gas requiring processing.

Fuel gas consumption by all plants has ranged from 5.15 to 5.62 percent of total deliveries, with an average usage of 5.35 percent over the ten-year period from 1972 to 1981. For the forecast period, consumption is assumed constant at 5.35 percent of total deliveries.

There are three main users of fuel gas within plants: reciprocating compressor engines, heaters and boilers, and tail gas incinerators (sour gas plants only). To determine the proportion of fuel gas used by each end user, results of an energy consumption survey (Berlie, Ritter, and Sames 1982) of rich sweet, lean sweet, rich acid, and lean acid gas processing plants were used. Results for each type of plant were weighted, based on 1980 fuel consumption and production data.

It was concluded that sweet plants use 33 percent of the fuel gas consumed by all plants, with 65 percent of this fuel being used by reciprocating compressor engines and 35 percent by heaters and boilers. Sour gas plants use 67 percent of all plant fuel gas, and 20 percent of this fuel is used by reciprocating compressor engines, 65 percent by heaters and boilers, and 15 percent by incinerators.

Overall, 35 percent of the total plant fuel gas is used by reciprocating compressor engines, 55 percent is used for process heating, and 10 percent is used by incinerators. It is recognized that there are gas turbines installed at gas plants but it is concluded that most are used for injection compression rather than gas processing.

4.1.1.4 Injection. Processed and raw gas is injected into reservoirs to maximize heavy hydrocarbon recovery and to maintain pressure. Fuel gas requirements for injection compressor engines have averaged 0.12 percent of total deliveries over the last ten years, and for the forecast period a constant value of 0.15 percent is used.

Compressor engine fuel usage is split approximately equally between reciprocating engines and gas turbines.

4.1.1.5 Transportation. A complex pipeline system exists in Alberta to deliver gas to residential, commercial, and industrial consumers within the province and to out-of-province customers. Gas from the pipelines is used to power the compressors that move the gas through the pipeline system.

Fuel gas consumption has decreased from 1.0 percent of total deliveries in 1972 to 0.5 percent in 1981 due to energy conservation measures. For the forecast period fuel gas consumption is assumed to remain constant at 0.5 percent of total deliveries.

Based on Alberta Environment's (1982a) listing of pipeline compressor stations, it is estimated that gas turbine compressor engines consume 90 percent and reciprocating compressor engines 10 percent of the fuel gas used for transportation.

4.1.1.6 Reprocessing. Reprocessing plants remove valuable ethane and heavier hydrocarbons from the gas flowing in major pipelines. The large power requirements of these plants have been historically met by gas turbines. However, conversion to electric motors to reduce fuel and operating costs is becoming economically favourable and several large straddle plants are converting to electric drives.

Fuel gas requirements of reprocessing plants have averaged 0.59 percent of total deliveries between 1972 and 1981. In 1980, consumption peaked at 0.75 percent of total deliveries. Considering the trend to electric drives, the fuel gas usage fraction will decrease.

Reprocessing plants are assumed to use 0.50 units of fuel for every 100 units of gas delivered for the entire forecast period. Eighty-five percent of the fuel gas is assumed to be used by gas turbine compressor engines and the remaining 15 percent by process heaters.

4.1.2 Oxides of Nitrogen Sources

On an overall industry basis, about 47 percent of the fuel gas is used in heaters and boilers. Reciprocating and gas turbine compressor engines consume 35 and 12 percent, respectively, of the fuel, and incinerators (used only in sulphur recovery plants) consume the remaining 6 percent. The NO_x emission factors for all of the above sources, considering present, best practicable, and best available technology, are summarized in Table 11. Each source is discussed separately in the following sections.

4.1.2.1 Reciprocating Compressor Engines. Reciprocating engines are used to power field, gathering, inlet, refrigeration, outlet, and distribution compressors. There is currently no accurate tabulation of compressor engines in Alberta. Alberta Environment's most recent (1982a, 1982b) listing of reciprocating engines at gas plants and compressor stations totals 655 units with an installed capacity of 650 MW. The compressor station listing is only for stations with a total power of 750 kW or more; therefore, smaller units installed in field and gathering systems are not accounted for and the listing for gas plants is incomplete. A study is currently in the process of being completed to bring this listing up to date (Legge 1983).

Oxides of nitrogen emissions per unit of fuel input from reciprocating engines are greater than for any other combustion device. Conditions which promote NO_x formation (high temperature, oxygen availability, and residence time) are all present in these engines. Emissions are also a function of actual engine design, operating conditions (load and speed), and ambient conditions (especially temperature).

Table 11. Natural gas industry NO_x source emission factors.^a

	PT (ng/J)	BPT (ng/J)	BAT (ng/J)
Heaters & Boilers	99	64	40
Gas Turbines	126	75	38
Reciprocating Engines	1481	889	296

^aas NO₂

An emission factor of 1481 ng/J ($55\,400\text{ kg}/10^6\text{m}^3$) is recommended by the US EPA (1981) and is used in the forecast. Some manufacturers quote higher peak emissions. The recommended factor is equivalent to about 956 ppm of NO_2 at 15 percent O_2 (dry basis) assuming pure methane as a fuel and typical fuel consumption figures. For comparison, the average value of over 30 stack surveys conducted by Western Research is 752 ppm (15 percent O_2 , dry basis). The difference may be due to the small sample size, the effect of ambient conditions, or the operating conditions. The larger value, used in previous Alberta NO_x emission estimates, is adopted for this study, and thus the forecast may overstate the emissions by about 25 percent.

Best practicable technology for reciprocating compressor engines consists of a combination of operational adjustments and hardware additions, as summarized by Zelensky (1982). Operational adjustments include changing the air-to-fuel ratio, retarding ignition timing, and de-rating the engine. Hardware additions include exhaust gas recirculation, redesigned combustion chambers, and reduced manifold air temperature. A combination of the above techniques could achieve NO_x reductions of 40 percent.

Best available technology for reciprocating engines is the installation of catalytic exhaust gas treatment systems which reduce NO_x to N_2 . Reductions of 80 percent or more should be attainable in the long term.

4.1.2.2 Gas Turbines. Gas turbines are normally used when power requirements are large, generally in excess of 1 MW. According to Alberta Environment (1982b), there are 43 turbine installations with a total installed power rating of 170 MW. The majority of these units are used for gas transportation, rather than distribution or gathering.

An emission factor of 126 ng/J ($4700\text{ kg}/10^6\text{m}^3$) fuel gas is considered representative of gas turbines (US EPA 1981). This is an order of magnitude less than that characteristic of reciprocating engines and is the result of lower combustion temperatures.

NO_x control methods for gas turbines are classified as either wet or dry (Zelensky 1982). Dry control involves improved combustor designs which influence the variables that affect NO_x production. Wet control involves the injection of water or steam into the combustion zone to reduce the peak flame temperature.

Dry control, which reduces NO_x emissions by 40 percent is considered to be best practicable technology. Wet control, to achieve reductions of 70 percent from present technology, is considered to be best available technology.

4.1.2.3 Large Electric Motors. Large electric motors are now being considered as an alternative to gas-fired drivers in some locations because of cost considerations. An all-electric processing and reprocessing plant exists. An ERCB (1982) analysis established that one-third of recent gas plant applications adopted electrified compression. Also, two reprocessing plants are being converted to all-electric drive. The increased use of electric motors causes an indirect emission of NO_x by electric utilities which are accounted for in Section 4.2.

Based on an average emission factor of 184 ng/J input (Section 4.2) for coal-fired power plants in Alberta and assuming power plant efficiency of 33 percent, line losses of 11 percent and electric motor efficiency of 90 percent, the equivalent emission factor is 688 ng NO_2 /J of shaft power. This compares to 4443 ng NO_2 /J of shaft power for reciprocating engines assuming an emission factor of 1481 ng NO_2 /J input and an efficiency of 33 percent. Gas turbines emit 504 ng NO_2 /J shaft power assuming an emission factor of 126 ng NO_2 /J input and an efficiency of 25 percent.

Based on the above examples, NO_x emission per unit of shaft power are thus reduced by about 85 percent when large electric motors are substituted for reciprocating engines and increase by about 25 percent when substituted for gas turbines.

In the forecast, increased usage of electric motors has been accounted for in the growth of industrial electric energy requirements. It was assumed that the fuel gas usage fraction for

reciprocating engines (Table 10) will remain constant and that electric motors provide the anticipated increased compression requirements (field, gathering, processing) for producing natural gas. For gas turbines, the reprocessing fuel gas usage fraction has been reduced and electric energy requirements have been increased to account for displacement by electric motors.

4.1.2.4 Heaters and Boilers. A wide variety of heaters and boilers are used in the gas industry. Emissions from each type are dependent on individual design and operating conditions.

For this study, an emission factor of 99 ng/J (3700 kg/10⁶m³) fuel gas is considered representative of present technology for heaters and boilers (US EPA 1981). Alberta Environment (1980) also used this factor for the NO_x emission inventory.

NO_x reductions of 35 percent can be achieved through application of best practicable technology. Best practicable technology consists of operational adjustments such as low excess air, flue gas recirculation, and off stoichiometric combustion, or minor retrofit modifications such as installing improved burners.

NO_x reductions of 60 percent can be achieved through application of best available technology consisting of extensive hardware changes and major redesign of new equipment.

4.1.2.5 Incinerators. During extensive field testing of incinerators to reduce fuel consumption, only trace amounts of NO_x were measured by Western Research. Temperature conditions within the incinerator do not promote NO_x formation.

NO_x emissions from incinerators are negligible and are expected to be insignificant for this forecast.

4.1.3 Potential Oxides of Nitrogen Emissions

Oxides of nitrogen emissions for the gas industry are forecast for the gas deliveries of scenarios A and B (Table 9) using the amount of fuel consumed per unit of gas delivered (Table 10) and the emission factors (Table 11). The timing of application of best practical and best available technology is outlined below.

4.1.3.1 Present Technology. Present technology reflects the current, uncontrolled level of emissions from each source. Table 12 lists the overall gas industry emission factors, expressed as t NO₂/PJ delivery, that were assumed for the entire forecast period. Reciprocating engines are responsible for about 90 percent of the total gas industry emissions and about 59 percent of the total emissions are from processing plant locations.

4.1.3.2 Best Practicable Technology. The application of best practicable control technology was expected to be initiated in 1986 and was phased in smoothly until fully implemented in all existing and new plants by 1990. A reduction in potential (uncontrolled) emissions of approximately 40 percent was projected.

4.1.3.3 Electric Motor Substitution Option. An alternative means of achieving emission levels attained through application of best practicable technology would be to replace reciprocating engines with electric motors. For each PJ of reciprocating engine fuel gas displaced, 1.23 PJ of coal must be consumed by a power plant (based on the efficiency assumptions of Section 4.1.2.3). Thus, overall provincial NO_x emissions are reduced by 1255 ng/J of reciprocating engine fuel gas displaced by electric motors assuming present technology. To achieve the same overall emissions estimated for best practicable technology, while maintaining emission factors from the gas industry and electric utility sources at the present technology levels, reciprocating engine fuel gas usage would have to be decreased by about half of the assumed level.

4.1.3.4 Best Available Technology. Best available control technology would decrease potential NO_x emissions from the gas industry by 78 percent once fully applied in 1995. Reductions would be phased in smoothly starting in 1991 and assuming existing sources have been reduced through the application of best practicable technology.

Table 12. Natural gas industry overall NO_x emission factors: present technology.

Category	Source			Total (t/PJ) ^a
	Reciprocating Engines (t/PJ) ^a	Gas Turbines (t/PJ) ^a	Heaters and Boilers (t/PJ) ^a	
Field	1.93	-	1.11	3.04
Gathering	14.81	0.06	-	14.87
Processing				
Sweet Gas	16.89	-	0.60	17.49
Sulphur Recovery	10.67	-	2.31	12.98
Injection	1.04	0.10	-	1.14
Transportation	0.74	0.57	-	1.31
Reprocessing	-	0.54	0.07	0.61
Total	46.08	1.27	4.09	51.44

^a t NO₂/PJ of gas delivered (t/PJ equivalent to ng/J)

4.1.3.5 Summary. Table 13 lists the estimated NO_x emissions by the natural gas industry considering present, best practicable, and best available technology for scenarios A and B. The forecast is shown in Figure 8.

4.2 Electric Utilities

NO_x emissions associated with the electric utilities result from the burning of coal and natural gas to meet the province's electrical requirements. Oxides of nitrogen emissions from burning coal are mostly fuel NO_x from nitrogen in the coal, while emissions from burning gas are mostly thermal NO_x .

4.2.1 Emission Factors

Reported emission factors (US EPA 1981) for uncontrolled coal-fired and gas-fired power boilers are 494 ng NO_2/J (9 kg/t) and 299 ng NO_2/J (11 200 kg/ 10^6m^3), respectively.

An emission factor representative of Alberta power plants was developed from emission data (Alberta Environment 1980), and fuel consumption and power generation data (ERCB 1982). It was determined that existing coal-fired power plants emit 184 ng NO_2/J and gas-fired power plants emit 113 ng NO_2/J . Emissions from small gas-fired power boilers were not included in the data. For these plants, an emission factor of 257 ng NO_2/J was used.

The above data may be compared with present federal emission guidelines of 258 ng/J for coal and 86 ng/J for natural gas. These guidelines are presently being reviewed by Alberta Environment.

4.2.2 Potential Oxides of Nitrogen Emissions

Emissions factors for coal- and gas-fired power plants are combined with the electric requirements to be met by burning coal and gas (Table 6) to forecast the NO_x emissions for electric utilities. NO_x emission forecasts are presented for both growth scenarios and for the all-coal options.

Table 13. Natural gas industry oxides of nitrogen emissions forecast.^a

Year	Scenario A			Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	310	310	310	310	310	310
1981 ^b	304	304	304	304	304	304
1982	331	331	331	331	331	331
1983	356	356	356	356	356	356
1984	452	452	452	398	398	398
1985	500	500	500	414	414	414
1986	516	452	452	427	370	370
1987	497	404	404	405	326	326
1988	481	355	355	385	282	282
1989	435	307	307	336	238	238
1990	427	258	258	324	196	196
1991	421	255	226	317	192	171
1992	415	250	192	314	189	146
1993	419	253	159	321	194	121
1994	419	253	126	323	195	96
1995	425	256	92	331	200	72
1996	430	260	94	338	204	74
1997	438	264	96	347	209	76
1998	445	269	97	355	214	77
1999	453	273	99	363	219	79
2000	461	278	101	372	225	81

^a as NO₂^b Actual data from Alberta Environment (1983).

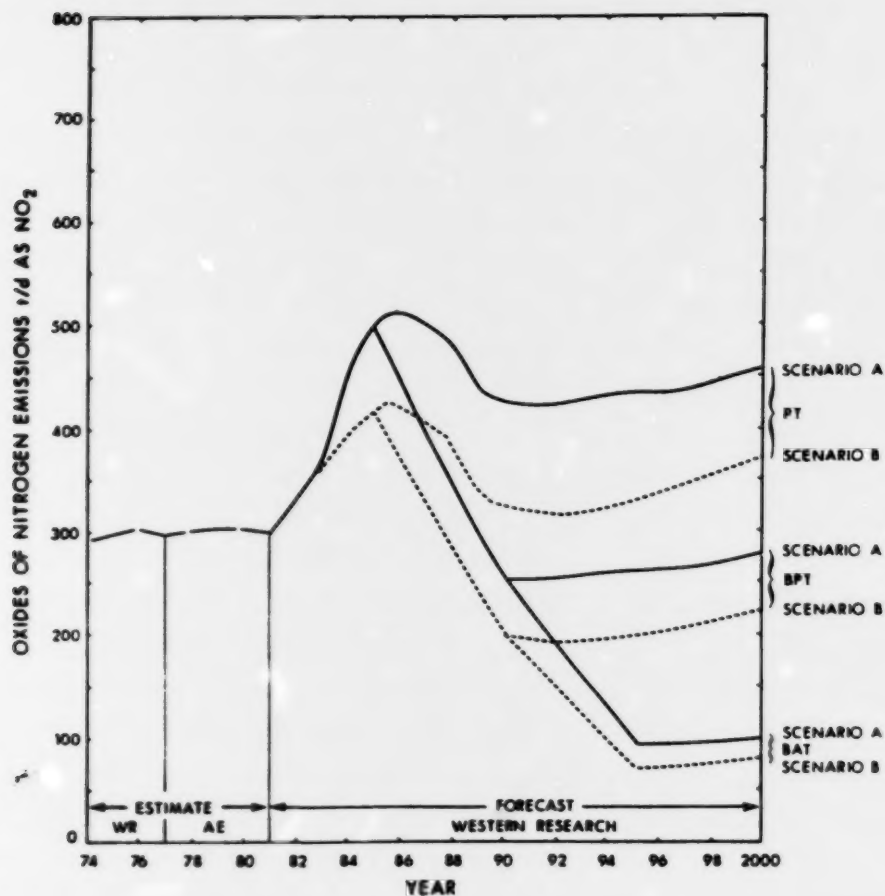


Figure 8. Natural gas industry emissions forecast. Estimates for emissions prior to 1981 are from Western Research (WR) and Alberta Environment (AE).

4.2.2.1 Present Technology. Present technology in Alberta for coal-fired power plants is no control. Existing gas-fired power plants use operational adjustments such as low excess air firing and flue gas recirculation to decrease oxides of nitrogen emissions.

4.2.2.2 Best Practicable Technology. Best practicable technology is considered to be operational adjustments and retrofitting of existing units. For new units, such technology is considered to be the incorporation of measures such as low excess air firing and flue gas recirculation into the design.

With the application of best practicable technology, it is estimated that a 35 percent reduction in NO_x emission from the present level can be achieved for coal-fired power plants. For gas-fired boilers, it is recognized that the existing boilers are practicing flue gas recirculation and low excess air firing and, therefore, an additional improvement of 5 percent from the present level can be expected. Best practicable technology is not applied to small gas-fired power boilers. For existing coal-fired plants and all future plants, best practicable technology would be implemented starting in 1986 and fully applied by 1990.

4.2.2.3. Best Available Technology. Fuel combustion modification combined with selective catalytic reduction is considered to be the best available technology for both coal-fired and gas-fired power boilers. The combination of these two methods would lead to a decrease in NO_x emissions of 80 and 90 percent for coal and gas-fired plants, respectively, relative to the uncontrolled levels. Operational adjustments, already used in gas-fired power plants, were again taken into consideration when the reduction achievable by using best available technology in gas-fired power plants was included in the forecast.

In this forecast it is assumed that the best available technology would be applied to existing and new stations (except for the group of small plants) between the years 1991 and 1995. It is also assumed that best practicable technology has been applied to existing plants. For the existing small gas-fired power plants, no control was applied and, therefore, the NO_x emissions remained the same as with present technology.

4.2.2.4 Summary. Emission factors used for the application of present, best practicable, and best available technology are summarized in Table 14. The resulting emission forecasts are summarized in Table 15 and shown in Figure 9.

4.3 OIL SANDS

Alberta's oil sands plants can be classified into two groups according to technology used: mining or in situ. At present, the only large scale plants are of the mining type, namely Suncor and Syncrude, and all in situ plants are pilot units. The main sources of oxides of nitrogen emissions in all types of oil sands plants are steam and power boilers, and process heaters.

4.3.1 Emissions Factors

To forecast the NO_x emissions of oil sands plants in Alberta, composite emission factors for Suncor, Syncrude, large scale mining, large scale in situ and in situ pilot plants are derived.

Major sources of NO_x emissions of the Suncor plant were identified as gas-fired power boilers, gas-fired steam boilers, and coke-fired power boilers. For the gas-fired power boilers, and gas-fired steam boilers, the emission factors reported by US EPA (1981) of 257 ng/J ($9600 \text{ kg}/10^6 \text{ m}^3$) and 99 ng/J ($3700 \text{ kg}/10^6 \text{ m}^3$), respectively, were used. For the coke-fired power boilers, the NO_x emission rate was considered to be equal to the weighted average of 184 ng/J for the existing coal-fired power plants in Alberta. These emission factors were combined with the fuel consumption data of the

Table 14. Electric utilities NO_x emission factors.^a

	PT (ng/J)	BPT (ng/J)	BAT (ng/J)
Coal-fired Boilers	184	120	37
Gas-fired (large) Boilers	113	107	12
Gas-fired (small) Boilers	257	257	257

^aas NO₂

Table 15. Electric utilities oxides of nitrogen emissions forecast.^a

Year	Scenario A			Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	116	116	116	116	116	116
1981 ^b	118	118	118	118	118	118
1982	140	140	140	134	134	134
1983	152	152	152	142	142	142
1984	164	164	164	151	151	151
1985	176	176	176	160	160	160
1986	186	171	171	168	155	155
1987	195	166	166	176	150	150
1988	205	161	161	184	145	145
1989	214	155	155	192	140	140
1990	224	150	150	201	136	136
1991	236	158	132	210	141	119
1992	248	166	114	218	147	102
1993	260	174	95	227	152	85
1994	272	181	77	236	158	68
1995	284	189	58	245	164	50
1996	297	198	61	253	169	52
1997	310	207	63	261	174	53
1998	323	216	66	269	180	55
1999	336	225	68	277	185	57
2000	350	233	71	286	191	58

^a as NO₂^b Actual data from Alberta Environment (1983)

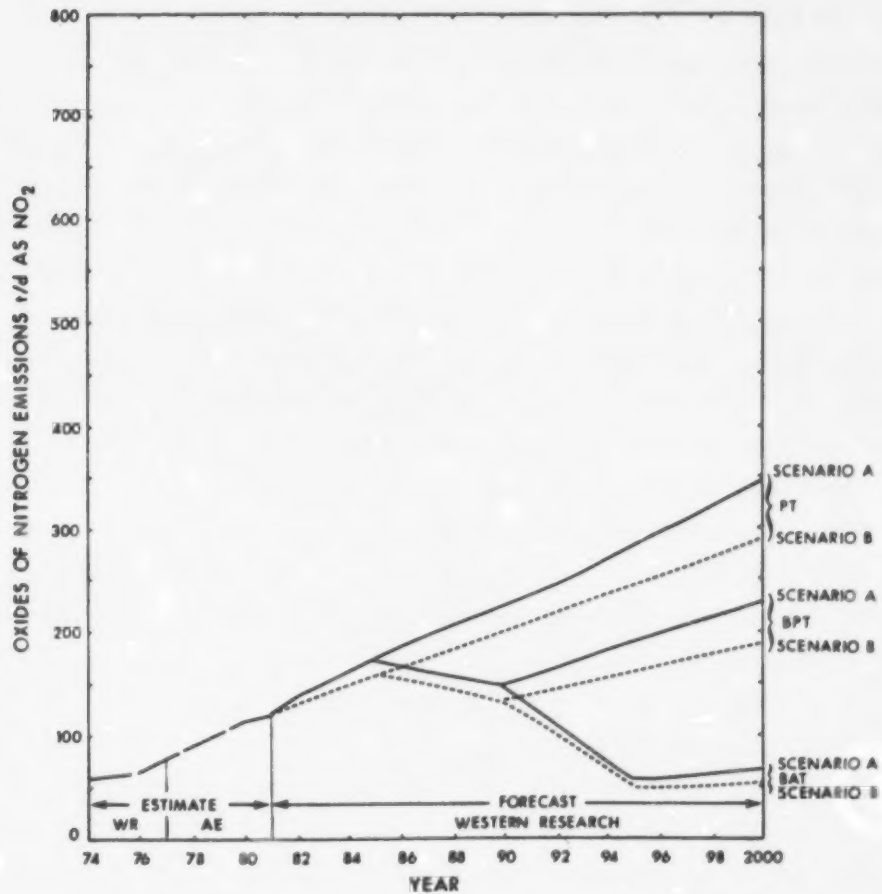


Figure 9. Electric utilities emissions forecast. Estimates for emissions prior to 1981 are from Western Research (WR) and Alberta Environment (AE).

gas-fired power boilers, gas-fired steam boilers and the coke-fired power boilers obtained through personal communication (1983 January 06 meeting with T. Walden and R. Houlihan of the ERCB, Calgary, Alberta) and the ERCB reports (73-N-OG and 79-A) to yield the composite emission factor for the Suncor plant.

Major sources of NO_x emissions of the Syncrude plant were identified as gas-fired power boilers, gas-fired steam boilers, and gas-fired CO boilers. For the gas-fired power boilers and gas-fired steam boilers, the US EPA (1981) data were used. For the gas-fired CO boilers, the calculated NO_x emission rate was determined to be $0.4 \text{ kg NO}_2/\text{m}^3$ synthetic crude oil (SCO) production. These emission factors were combined with the natural gas consumption and synthetic crude oil production data obtained through personal communication with ERCB and ERCB reports (ERCB 73-K-HE-OG) to yield the composite emission factor for the Syncrude plant.

The composite emission factor for future large scale mining plants was assumed to be similar to that of the Syncrude plant.

Examination of an ERCB report (ERCB 81-C) for the Cold Lake project indicated that the gas-fired steam boilers are the only sources of NO_x emissions. No gas-fired power boilers were considered as all electric energy would be purchased. This was taken to be representative of future large scale in situ oil sands plants in Alberta. The emission factor of 99 ng/J ($3700 \text{ kg}/10^6 \text{ m}^3$) reported by US EPA (1981) for gas-fired steam boilers was combined with the natural gas consumption data in the ERCB report to give the composite emission factor for large scale in situ plants.

For the in situ pilot plants, the only sources of NO_x emissions were considered to be gas-fired steam boilers and all electric energy would be purchased. Data obtained from the ERCB regarding natural gas consumption for the steam boilers in the pilot plants was combined with the emission factor reported by US EPA to give the composite emission factor for in situ pilot plants.

Table 16 summarizes the composite emission factors for the various types of oil sands plants.

Table 16. Oil sands composite NO_x emission factors.^a

	PT (kg/m ³ SCO)	BPT (kg/m ³ SCO)	BAT (kg/m ³ SCO)
Suncor	2.22	1.41	0.38
Syncrude	1.20	0.78	0.12
Mining Plant	1.20	0.78	0.12
In Situ Plant (large)	1.20	0.78	0.12
In Situ Plant (pilot)	1.32	0.86	0.53

^aas NO_2

4.3.2 Potential Oxides of Nitrogen Emissions

Production levels for growth scenarios A and B (Figure 4) are used to forecast the maximum potential NO_x emission levels for oil sands plants in Alberta. Actual emission levels are anticipated to be 70 to 90 percent of maximum potential levels and to be conservative in this forecast; future emissions are estimated to be 90 percent of maximum potential emissions on an annual average basis, except when emission control equipment is applied. Increased synthetic crude oil production forecast for Scenario A is assumed to be provided equally by large scale mining and in situ plants.

4.3.2.1 Present Technology. Present technology is reflected by the industry average emission level considering Suncor, Syncrude, existing pilot, and proposed mining and in situ plants.

4.3.2.2 Best Practicable Technology. For the various boilers and heaters used in the oil sands plants, best practicable technology for the control of oxides of nitrogen emissions is based on the same principles as those for other boilers and heaters in Alberta. These include operational adjustments, small scale retrofitting to allow burning with low excess air, flue gas recirculation, and staged burning.

Application of best practicable technology would result in a 35 percent NO_x reduction for coke-fired power boilers, a 50 percent reduction for gas-fired power boilers, and a 35 percent reduction for gas-fired steam boilers.

For existing oil sands plants, best practicable technology would be applied in 1990. For new plants, best practicable technology would be applied as it becomes operational.

4.3.2.3 Best Available Technology. Best available technology is considered to be a combination of retrofitted or new-design boilers and heaters, and new selective catalytic systems. The selective catalytic systems would be applied to the power boilers and all

other steam boilers and heaters. The resulting decrease in production of the oxides of nitrogen from coke-fired power boilers would be in the range of 80 percent and for all other gas-fired boilers and heaters about 90 percent of the present level.

For existing oil sands plants, best available technology would be applied in 1995, assuming the application of best practicable technology in 1990. For new oil sands plants, best available technology would be applied when constructed.

4.3.2.4 Summary. Table 17 summarizes the oxides of nitrogen emissions forecast for scenarios A and B. The forecast is shown in Figure 10.

4.4 OTHER INDUSTRIES

4.4.1 Potential Oxides of Nitrogen Emissions

An emission factor of 257 ng NO₂/J of natural gas input, as reported by the US EPA (1981), was used together with the fuel forecasts in Tables 7 and 8 to derive the forecast of oxides of nitrogen emissions from the other industries sector. The emission factor was found to be in reasonable agreement with the average emission factor calculated for 1980 and 1981 using the fuel estimates of EUPC (1981), and Alberta Environment emission estimates for the refineries, pulp and paper, cement, fertilizers, and chemical industries (Alberta Environment 1983).

Industries in this sector for which Alberta Environment reports emissions consume about 60% of the total fuel consumed by the sector as estimated for this study. Consequently, the emission forecast for this sector is higher than that reported by Alberta Environment.

4.4.1.1 Present Technology. Present technology reflects no control of NO_x emissions from new and existing industrial boilers in Alberta.

Table 17. Oil sands oxides of nitrogen emissions forecast.^a

Year	Scenario A			Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	24	24	24	24	24	24
1981 ^b	27	27	27	27	27	27
1982	39	39	39	39	39	39
1983	43	43	43	43	43	43
1984	44	44	44	44	44	44
1985	45	45	45	45	45	45
1986	46	46	46	46	46	46
1987	46	46	46	46	46	46
1988	46	46	46	46	46	46
1989	46	46	46	46	46	46
1990	46	28	28	46	28	28
1991	49	30	30	46	28	28
1992	55	34	34	46	28	28
1993	59	37	37	46	28	28
1994	65	40	40	46	28	28
1995	70	43	10	46	28	7
1996	75	46	10	46	28	7
1997	81	50	11	46	28	7
1998	86	53	11	46	28	7
1999	91	56	12	46	28	7
2000	97	62	13	46	28	7

^a as NO₂^b Actual data from Alberta Environment (1983)

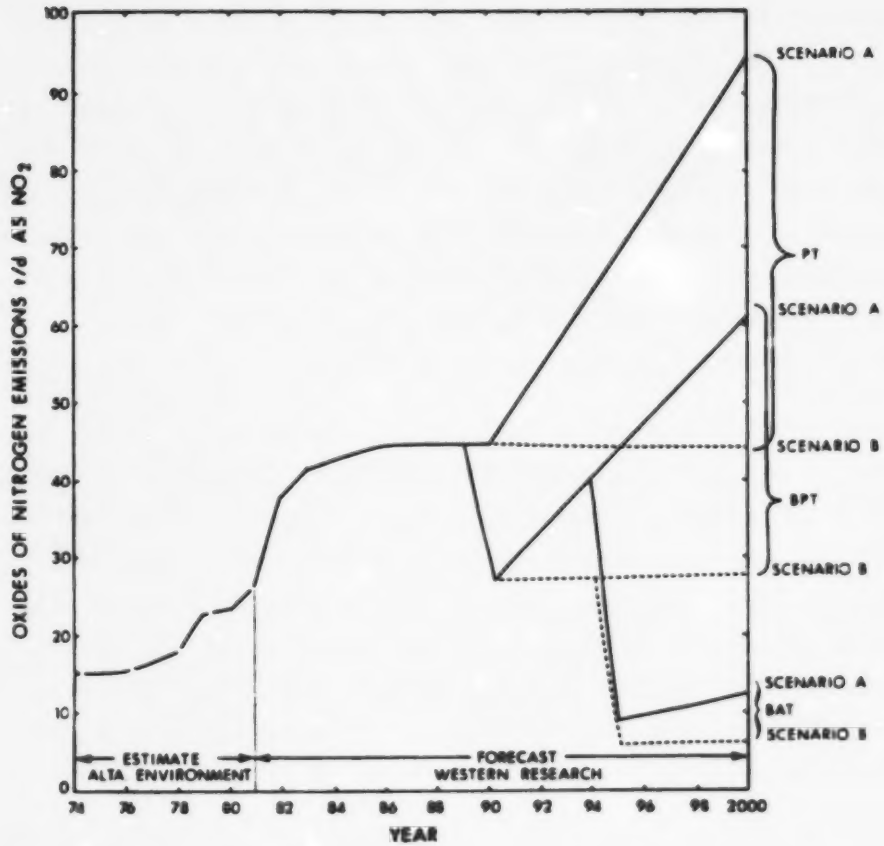


Figure 10. Oil sands emissions forecast.

4.4.1.2 Best Practicable Technology. The methods available for decreasing oxides of nitrogen emissions from industrial boilers do not differ from the methods available for large utility boilers.

Best practicable control technology for industrial boilers is considered to be operational adjustments and minor retrofit modifications, using methods such as low excess combustion air, flue gas recirculation, off stoichiometric combustion, or low NO_x burners. Through these methods a 50 percent decrease in oxides of nitrogen emissions relative to present technology is estimated. Best practicable technology in all industrial boilers would be phased in over five years starting in 1985.

4.4.1.3 Best Available Technology. Catalytic systems for NO_x control are not considered best available technology for industrial boilers. Instead, extensive hardware changes and major redesign of new equipment is considered applicable to this group of sources. The estimate of the decrease in oxides of nitrogen emissions relative to present levels is estimated to be 60 percent. Best available technology would be applied to existing sources starting in 1990, assuming the application of best practicable technology starting in 1985.

4.4.1.4 Summary. Emission factors used for present, best practicable, and best available technology are summarized in Table 18. The forecast of the oxides of nitrogen emissions from the industrial sources is given in Table 19 and Figure 11.

4.5 TRANSPORTATION

The transportation sector includes passenger car, commercial vehicles, and railway locomotive sources of oxides of nitrogen.

4.5.1 Passenger Cars

To estimate oxides of nitrogen emissions from passenger cars, the simplified version of Environment Canada's Urban Road Transportation Emission Inventory (URTEI) model is adopted. For this approach, several parameters which affect oxides of nitrogen emissions are considered, including vehicle age distribution, vehicle degradation factor, and new vehicle emission levels. Data

Table 18. Other industries NO_x emission factors.^a

	PT (ng/J)	BPT (ng/J)	BAT (ng/J)
Medium-size, Gas-fired Industrial Boilers	257	129	103

^a
as NO₂

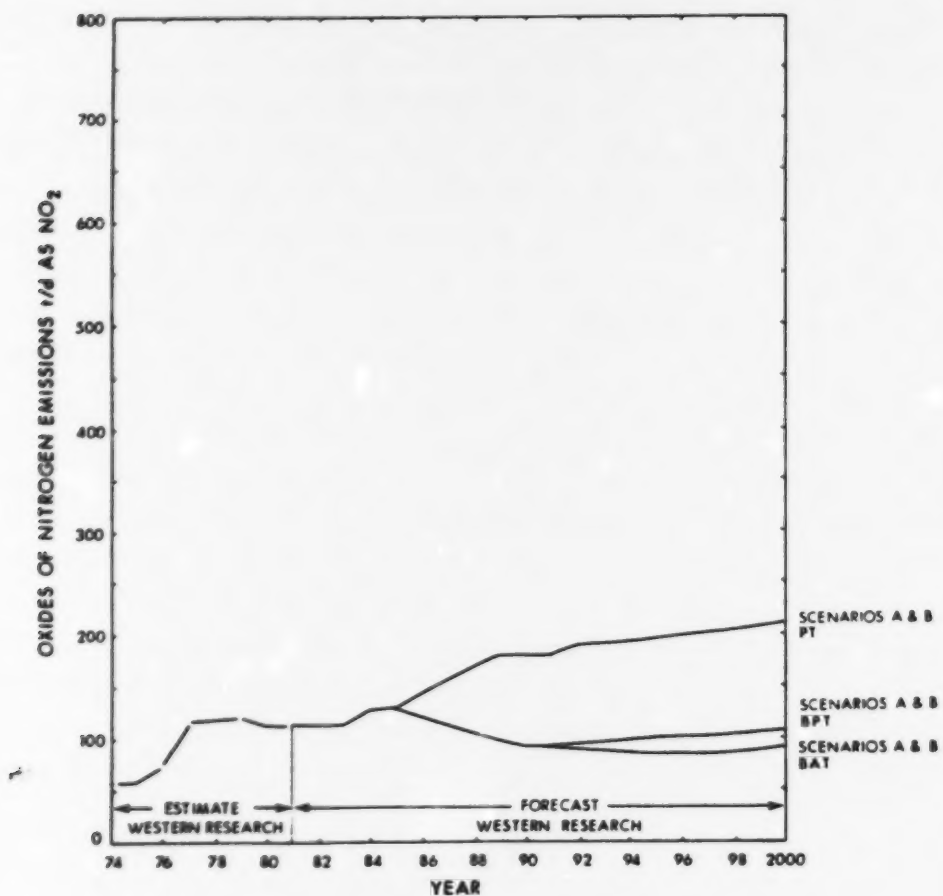


Figure 11. Other industries emissions forecast.

Table 19. Other industries oxides of nitrogen emissions forecast.^a

Year	Scenarios A and B		
	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	109	109	109
1981 ^b	112	112	112
1982	112	112	112
1983	112	112	112
1984	127	127	127
1985	127	127	127
1986	143	120	120
1987	156	112	112
1988	171	105	105
1989	179	97	97
1990	179	90	90
1991	179	90	90
1992	189	95	88
1993	189	95	86
1994	195	98	84
1995	195	98	82
1996	200	100	80
1997	200	100	80
1988	205	103	83
1999	210	105	83
2000	215	108	86

^a as NO₂^b Estimated by Western Research

regarding new vehicle emission levels are derived from Environment Canada's in-house emission testing of new vehicles under Transport Canada's new vehicle compliance program (letter dated 1982 December 10 from Dave Gourley, In-use Vehicles Engineer, Environment Canada, Mobile Sources Division). The testing program provides data on the emission capability of new cars when adjusted to manufacturer's specifications. The data normally reflect the biggest selling car line of each major domestic and import manufacturer so that, with the application of sales weighting factors, a reasonably accurate fleet average emission factor for a given model year of new vehicles can be calculated.

Other parameters such as the vehicle age distribution and vehicle degradation factors are obtained from Environment Canada's in-use vehicle testing programs which are held periodically across Canada (letter dated 1982 December 10 from Dave Gourley, Environment Canada, Mobile Sources Division). With the input of the vehicle age distribution and vehicle degradations due to poor tuning, engine wear, and tampering with emission control systems, the new vehicle emission factor is adjusted to give the composite emission factor for passenger cars in a given year (letter dated 1983 February 21 from D. Gourley, Environment Canada, Mobile Sources Division). Table 20 summarizes the composite emission factors for passenger cars with the application of PT, BPT, and BAT.

Based on the in-use vehicle testing program carried out by Environment Canada, it is estimated the average annual vehicle distance travelled for passenger cars is 18 520 km.

The composite emission factors, average vehicle distance travelled, and the passenger vehicle growth profiles (Table 3) are used to forecast the potential NO_x emission from passenger vehicles in Alberta. Oxides of nitrogen emissions are presented for both growth scenarios. Table 21 summarizes the emissions forecasts.

4.5.1.1 Present Technology. Present technology for passenger vehicles in Alberta is the application of technology such as exhaust gas recirculation (EGR) to meet the current Canadian standard of

Table 20. Composite NO_x emission factors for passenger cars.^a

Year	PT (g/km)	BPT (g/km)	BAT (g/km)
1980	1.81	1.81	1.81
1981	1.73	1.73	1.73
1982	1.57	1.57	1.57
1983	1.54	1.54	1.54
1984	1.47	1.47	1.47
1985	1.46	1.46	1.46
1986	1.46	1.43	1.43
1987	1.44	1.31	1.31
1988	1.42	1.20	1.20
1989	1.38	1.07	1.07
1990	1.35	0.97	0.93
1991	1.37	0.94	0.86
1992	1.37	0.87	0.77
1993	1.37	0.78	0.70
1994	1.37	0.78	0.63
1995	1.37	0.68	0.53
1996	1.37	0.68	0.50
1997	1.37	0.68	0.47
1998	1.37	0.68	0.43
1999	1.37	0.68	0.36
2000	1.37	0.68	0.36

^aas NO₂

Table 21. Passenger cars oxides of nitrogen emissions forecast.^a

Year	Scenario A			Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	105	105	105	105	105	105
1981 ^b	105	105	105	105	105	105
1982	101	101	101	94	94	94
1983	101	101	101	94	94	94
1984	101	101	101	94	94	94
1985	102	102	102	96	96	96
1986	107	104	104	100	97	97
1987	109	99	99	101	92	92
1988	112	95	95	102	86	86
1989	114	89	89	102	80	80
1990	116	83	80	103	74	71
1991	122	83	76	108	74	67
1992	127	81	71	110	70	62
1993	132	80	67	113	69	58
1994	137	78	62	116	66	53
1995	141	70	55	119	59	46
1996	146	73	53	122	61	44
1997	151	75	51	125	62	42
1998	157	78	50	128	64	40
1999	162	80	43	131	65	34
2000	167	83	44	134	66	35

^a as NO₂^b Estimated by Western Research

1.9 g/km for new, light-duty vehicles. This standard will remain unchanged during the forecast period.

4.5.1.2. Best Practicable Technology. Best practicable technology is considered to be the application of three-way catalytic converters to meet the emission level of 0.6 g/km for new, light-duty vehicles. This improved technology is applied in 1986 and remains unchanged during the forecast period.

4.5.1.3 Best Available Technology. Best available technology is considered to be the application of NO_x emission control technologies such as closed loop carburetor control, air injection reactor, electronic spark timing, and idle speed control together with a three-way catalytic converter to meet the emission level of 0.2 g/km for new passenger cars. For best available technology, the emission level of 0.6 g/km would be achieved in 1986, and by 1990 the level of 0.2 g/km would be achieved and would remain unchanged during the forecast period.

4.5.2 Commercial Vehicles

For this forecast, commercial vehicle growth profiles delineated in Table 4 are considered to be comprised of light duty trucks, medium duty trucks, heavy duty gasoline trucks, and heavy duty diesel trucks. Through personal communications with Motor Vehicle Division (telephone conversation on 1983 January 12 with Peter Wong, Special Projects Co-ordinator, Motor Vehicles Division, Alberta Solicitor General) and the data contained in the Environment Canada report "Canadian Urban Trucking Study (1974)," it is assumed that the commercial vehicle population consists of the following truck size components:

- | | |
|---------------------------------|----------------|
| 1. light-duty trucks | - 63.2 percent |
| 2. medium-duty trucks | - 18.9 percent |
| 3. heavy-duty trucks (gasoline) | - 6.7 percent |
| 4. heavy-duty trucks (diesel) | - 11.2 percent |

The commercial vehicle forecasts for each growth scenario are broken down into various truck size components in accordance with the above percentages.

The URTEI model is used to estimate the NO_x emissions from the various sizes of trucks. As mentioned in the previous section regarding passenger cars, the URTEI model takes into account parameters such as age distribution and degradation due to poor tuning, engine wear, and tampering to adjust the emission level to yield the composite emission factor for trucks of various ages in a given year. Table 22 summarizes the composite emission factor for the various sizes of trucks.

Average annual vehicle distance travelled data were obtained by Environment Canada through in-use vehicle testing programs. They are summarized as follows:

- | | |
|---------------------------------|-------------|
| 1. light duty trucks | - 15 770 km |
| 2. medium duty trucks | - 19 780 km |
| 3. heavy duty trucks (gasoline) | - 21 800 km |
| 4. heavy duty trucks (diesel) | - 80 520 km |

The composite emission factors, together with average annual distance travelled and growth profiles of trucks of various sizes, yield the potential NO_x emissions from commercial vehicles in Alberta. Table 23 summarizes the emission forecasts.

4.5.2.1 Present Technology. Present technology is considered to be the application of NO_x emission control technology such as exhaust gas recirculation to meet the following emission levels for new trucks of various sizes during the entire forecast period:

- | | |
|---------------------------------|-------------|
| 1. light-duty trucks | - 1.9 g/km |
| 2. medium-duty trucks | - 1.9 g/km |
| 3. heavy-duty trucks (gasoline) | - 5.8 g/km |
| 4. heavy-duty trucks (diesel) | - 14.2 g/km |

4.5.2.2 Best Practicable Technology. Best practicable technology is considered to be the application of systems which include a three-way catalytic converter with closed loop carburetor control to

Table 22. Composite NO_x emission factors for commercial vehicles.^a

Year	Light Duty Trucks			Medium Duty Trucks			Heavy Duty Trucks (Gasoline)			Heavy Duty Trucks (Diesel)		
	PT (g/km)	BPT (g/km)	BAT (g/km)	PT (g/km)	SP (g/km)	BAT (g/km)	PT (g/km)	BPT (g/km)	BAT (g/km)	PT (g/km)	BPT (g/km)	BAT (g/km)
1980	1.76	1.76	1.76	2.34	2.34	2.34	5.98	5.98	5.98	14.2	14.2	14.2
1981	1.70	1.70	1.70	2.09	2.09	2.09	5.86	5.86	5.86	14.2	14.2	14.2
1982	1.55	1.55	1.55	1.98	1.98	1.98	5.75	5.75	5.75	14.2	14.2	14.2
1983	1.47	1.47	1.47	1.96	1.96	1.96	5.49	5.49	5.49	14.2	14.2	14.2
1984	1.47	1.47	1.47	1.91	1.91	1.91	5.46	5.46	5.46	14.2	14.2	14.2
1985	1.44	1.44	1.44	1.88	1.88	1.88	5.44	5.44	5.44	14.2	14.2	14.2
1986	1.44	1.40	1.40	1.88	1.49	1.49	5.44	4.92	4.92	14.2	10.8	10.8
1987	1.42	1.28	1.28	1.84	1.22	1.22	5.39	4.57	4.57	14.2	9.25	9.25
1988	1.40	1.19	1.19	1.78	1.02	1.02	5.16	4.28	4.28	14.2	8.39	8.39
1989	1.34	1.07	1.07	1.78	0.94	0.94	5.28	4.12	4.12	14.2	7.00	7.00
1990	1.33	0.99	1.02	1.80	0.91	0.90	5.28	4.02	3.70	14.2	5.85	5.85
1991	1.32	0.93	0.93	1.80	0.88	0.83	5.28	3.96	3.37	14.2	5.00	5.00
1992	1.32	0.88	0.86	1.80	0.86	0.78	5.28	3.93	3.13	14.2	4.48	4.48
1993	1.32	0.84	0.81	1.80	0.85	0.74	5.28	3.88	2.90	14.2	4.06	4.06
1994	1.32	0.81	0.77	1.80	0.85	0.72	5.28	3.86	2.74	14.2	3.75	3.75
1995	1.32	0.70	0.63	1.80	0.82	0.69	5.28	3.70	2.50	14.2	3.33	3.33
1996	1.32	0.70	0.62	1.80	0.82	0.68	5.28	3.70	2.44	14.2	3.33	3.33
1997	1.32	0.70	0.62	1.80	0.82	0.67	5.28	3.70	2.38	14.2	3.33	3.33
1998	1.32	0.70	0.52	1.80	0.82	0.67	5.28	3.70	2.34	14.2	3.33	3.33
1999	1.29	0.70	0.56	1.80	0.82	0.66	5.28	3.70	2.10	14.2	3.33	3.33
2000	1.32	0.70	0.56	1.80	0.82	0.66	5.28	3.70	2.10	14.2	3.33	3.33

^a as NO₂

Table 23. Commercial vehicles oxides of nitrogen emissions forecast.^a

Year	Scenario A			Scenario B		
	PT (t/d)	PBT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	207	207	207	207	207	207
1981 ^b	209	209	209	209	209	209
1982	224	224	224	212	212	212
1983	232	232	232	224	224	224
1984	242	242	242	232	232	232
1985	252	252	252	239	239	239
1986	264	207	207	246	194	194
1987	274	187	187	253	173	173
1988	285	178	178	260	162	162
1989	298	159	159	267	142	142
1990	308	142	142	275	126	126
1991	321	130	128	282	115	113
1992	333	124	121	290	108	105
1993	346	119	115	298	103	99
1994	359	117	111	306	99	94
1995	372	108	102	314	91	86
1996	386	112	105	322	94	87
1997	400	116	108	330	96	89
1998	414	120	112	338	98	91
1999	428	125	116	346	101	91
2000	443	129	117	355	103	93

^a as NO_x^b Estimated by Western Research

meet the following emission levels:

- | | |
|---------------------------------|------------|
| 1. light-duty trucks | - 0.6 g/km |
| 2. medium-duty trucks | - 0.6 g/km |
| 3. heavy-duty trucks (gasoline) | - 3.0 g/km |
| 4. heavy-duty trucks (diesel) | - 3.3 g/km |

These levels would be achieved in 1986 and would remain unchanged during the forecast period.

4.5.2.3 Best Available Technology. Best available technology is considered to be the full application of the three-way catalytic converter with closed loop carburetor control, an air injection reactor, exhaust gas recirculation, electronic spark timing, and idle speed control to meet the following emission levels for new trucks of various sizes:

- | | |
|---------------------------------|------------|
| 1. light-duty trucks | - 0.2 g/km |
| 2. medium-duty trucks | - 0.4 g/km |
| 3. heavy-duty trucks (gasoline) | - 1.2 g/km |
| 4. heavy-duty trucks (diesel) | - 3.3 g/km |

For best available technology, best practicable technology levels would be met in 1986, and the above levels would be met in 1990 and would remain unchanged for the remainder of the forecast period.

4.5.3 Railways

Railway-based oxides of nitrogen are emissions from railway locomotives, most of which have large diesel engines. No electrification of rail lines is assumed over the forecast period.

The emission factors used for the application of present, best practicable, and best available technology are summarized in Table 24. Table 25 summarizes the NO_x emission forecast for railway locomotives.

4.5.3.1 Present Technology. Data regarding oxides of nitrogen emissions from railway locomotives are limited. Based on the data published by US EPA (1981), the average NO_x emissions from railway

Table 24. Railway NO_x emission factor.^a

	PT (kg/10 ³ L)	BPT (kg/10 ³ L)	BAT (kg/10 ³ L)
Railway Diesel Locomotives	44	35	22

^aas NO₂

Table 25. Railway oxides of Nitrogen Emissions Forecast.^a

Year	Scenario A & Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	37	37	37
1981 ^b	38	38	38
1982	40	40	40
1983	41	41	41
1984	43	43	43
1985	44	42	42
1986	46	41	41
1987	47	40	40
1988	49	39	39
1989	50	40	40
1990	52	42	42
1991	54	43	40
1992	55	44	39
1993	57	45	37
1994	58	46	35
1995	60	48	33
1996	61	49	31
1987	63	50	31
1998	64	51	32
1999	66	53	34
2000	67	54	34

^a as NO₂^b Estimated by Western Research

locomotives are 44 kg per 1000 litres diesel fuel oil burned. This is considered to be present technology.

4.5.3.2 Best Practicable Technology. To a large extent, control of NO_x emissions from railway locomotives is similar to that of light-duty diesels. For best practicable technology, it is considered that the application of retarded injection timing would effectively reduce NO_x emissions by 20 percent and that this technology would be applied gradually starting in 1985.

4.5.3.3 Best Available Technology. Other NO_x control methods such as improved-design fuel injections, humidification of inlet air, reduction of scavenging efficiency, and exhaust gas recirculation can effectively reduce NO_x emissions. Best available technology is considered to be combinations of the above control methods and results in a reduction of NO_x emissions by 50 percent. Best practicable technology would be applied between 1985 and 1989; best available technology would be phased in after 1990.

4.5.4 Summary

The forecasts of emissions from passenger cars, commercial vehicles, and railway locomotives are combined to give the emission forecasts for the transportation sector. They are summarized graphically in Figure 12.

4.6 RESIDENTIAL AND COMMERCIAL

Oxides of nitrogen emissions from residential and commercial sources are relatively small compared to other sources in Alberta. Each sector is discussed in the following sections.

4.6.1 Residential Sector

Residential heaters and boilers include all units less than 0.12 MW in size and in total are one of the smaller sources of oxides of nitrogen. The greatest amount of non-electric heating energy is supplied by natural gas. The remainder is supplied by

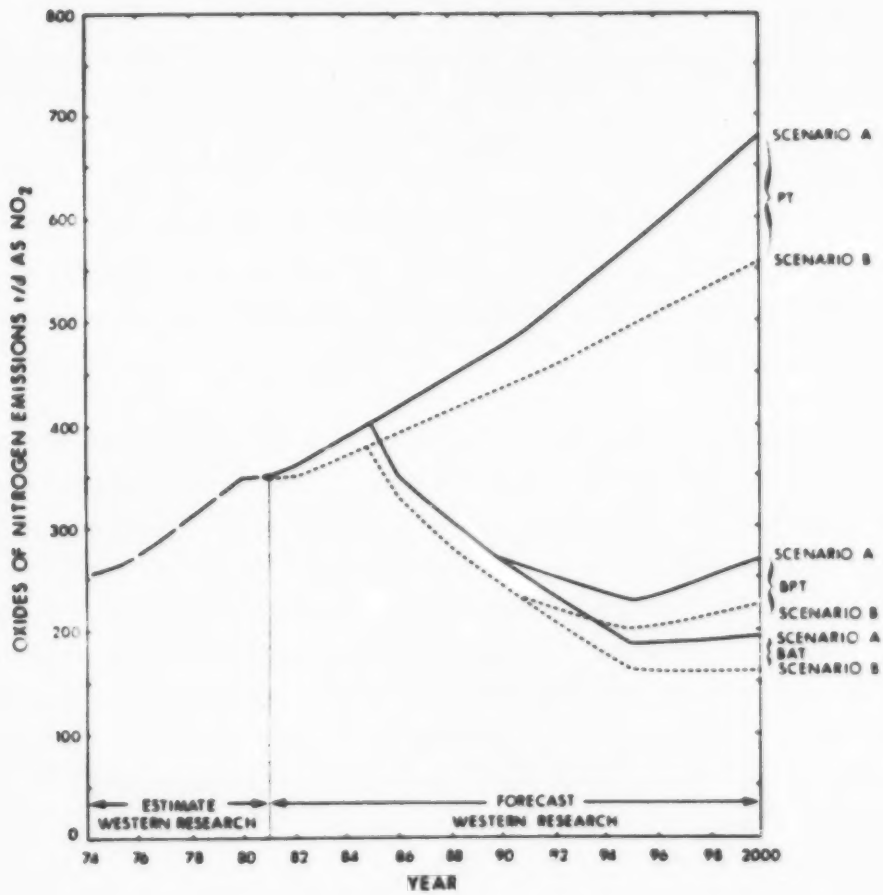


Figure 12. Transportation sector emissions forecast.

propane and fuel oil. In the future, the portion supplied by propane and fuel oil is expected to steadily decrease and by 1990 will be negligible.

The oxides of nitrogen emissions forecast was calculated on the basis of the two growth scenarios for residential fuel consumption. The amount of propane and fuel oils used was kept the same for both scenarios.

Emission factors used for present technology, best practicable technology, and best available technology are summarized in Table 26. Table 27 is a tabulation of emissions for the forecast period.

4.6.1.1 Present Technology. The major domestic combustion sources are central air furnaces, room or direct heaters, residential hot water heaters, and steam and hot water (hydronic) boilers for space and water heating. Minor sources include stoves and fireplaces.

As natural gas and even the distillate oils contain very small amounts of chemically bonded nitrogen and because the temperature of burning is low relative to large industrial units, the formation of the oxides of nitrogen is usually low. Estimated emissions from residential units are 34 ng/J (1280 kg/10⁶m³) for gas-fired, 32 ng/J (0.8 kg/10³L) for propane-fired, and 58 ng/J (1.5 kg/10³L) for oil-fired (US EPA 1981).

4.6.1.2 Best Practicable Technology. New furnaces and boilers achieve lower NO_x emission levels by cooling the flame, by lowering the excess air for burning, or by using more properly sized furnaces.

For gas-fired residential units, the technology includes modulating furnaces, heat transfer module furnaces, and pulse combustors. These methods decrease oxides of nitrogen emissions to 60 percent of levels produced by present systems. The same level is considered for propane-fired units.

Table 26. Residential sector NO_x emission factors.^a

	PT (ng/J)	BPT (ng/J)	BAT (ng/J)
Gas-fired Units	34	20	10
Propane-fired Units	32	19	10
Oil-fired Units	58	46	17

^a
as NO₂

Table 27. Residential sector oxides of nitrogen emissions forecast.^a

Year	Scenario A			Scenario B		
	PT	BPT	BAT	PT	BPT	BAT
	(t/d)	(t/d)	(t/d)	(t/d)	(t/d)	(t/d)
1980 ^b	10	10	10	10	10	10
1981 ^b	11	11	11	11	11	11
1982	12	12	12	11	11	11
1983	12	12	12	12	12	12
1984	12	12	12	12	12	12
1985	12	12	12	11	11	11
1986	12	11	11	11	10	10
1987	13	10	10	12	10	10
1988	13	9	9	12	9	9
1989	13	9	9	12	8	8
1990	13	8	8	12	7	7
1991	13	8	7	11	7	6
1992	13	8	6	11	7	6
1993	13	8	6	11	7	5
1994	13	8	5	11	7	4
1995	14	8	4	11	7	4
1996	14	8	4	12	7	4
1997	14	8	4	12	7	4
1998	14	8	4	12	7	4
1999	14	8	4	12	7	4
2000	14	8	4	12	7	4

^a as NO₂^b Estimated by Western Research

For oil-fired residential units, the technology includes new burners and furnaces using controlled mixing burner heads. Emission reductions of 80 percent are expected for these systems.

Best practicable technology would be phased in gradually from 1985 to 1990.

4.6.1.3 Best Available Technology. Best available technology is considered to be the new burners and furnace systems which are now in the stage of research and development.

For gas-fired units, best available technology is considered to be screen and surface combustion burners. Both are capable of decreasing oxides of nitrogen emissions by about 70 percent of those presently emitted from heaters and boilers. The same level is considered for propane-fired units.

For oil-fired units, best available technology includes Blue-ray burners and German MAN burners, and integral furnace designs with controlled mixing burner heads. For these units, the decrease in oxides of nitrogen emissions is considered to be 70 percent of present level.

Best available technology would be applied gradually from 1990 to 1995, assuming best practicable technology had previously been applied.

4.6.2 Commercial Sector

Commercial boilers include units having a heat input capacity of between 0.12 and 2.9 MW and exclusively using natural gas as fuel. The two forecasts of oxides of nitrogen emission from commercial sources are based on the two scenarios of commercial gas requirements.

Emission factors are summarized in Table 28. Table 29 is a tabulation of emission for the forecast period considering application of PT, BPT, and BAT.

Table 28. Commercial sector NO_x emission factors.^a

	PT (ng/J)	BPT (ng/J)	BAT (ng/J)
Gas-fired Units	51	33	20

^aas NO₂

Table 29. Commercial sector oxides of nitrogen emission forecast.^a

Year	Scenario A			Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980 ^b	13	13	13	13	13	13
1981 ^b	12	12	12	12	12	12
1982	11	11	11	11	11	11
1983	11	11	11	11	11	11
1984	11	11	11	11	11	11
1985	11	11	11	11	11	11
1986	12	11	11	11	10	10
1987	13	11	11	12	10	10
1988	13	10	10	12	9	9
1989	13	9	9	12	9	9
1990	14	9	9	12	8	8
1991	14	9	8	12	8	7
1992	14	9	8	12	8	7
1993	15	9	7	13	8	6
1994	15	10	7	13	8	6
1995	16	10	6	13	9	6
1996	17	11	7	14	9	6
1997	17	11	7	14	9	6
1998	18	11	7	14	9	6
1999	18	12	7	15	10	6
2000	19	12	8	15	10	6

^aas NO₂^bEstimated by Western Research

4.6.2.1 Present Technology. The major commercial combustion sources are warm air space or unit heaters, warm air furnaces, and hot water and steam boilers. For these relatively small heating units, the estimated emission factor is 51 ng/J (1920 kg/10⁶m³) of natural gas (US EPA 1981).

4.6.2.2 Best Practicable Technology. For commercial heaters and boilers, the oxides of nitrogen control techniques have not been widely investigated and the control technology is very limited. Possible control alternatives are:

1. low excess air for burning;
2. flue gas recirculation; and
3. heat load reduction.

On the basis of data available for industrial boilers and heaters and very limited data available for commercial sources, a 35 percent decrease in emissions by using best practicable technology was estimated. Best practicable technology includes operational adjustments and smaller retrofittings using the above-mentioned principles. Technology to achieve this is expected to be phased in from 1985 to 1990.

4.6.2.3 Best Available Technology. Best available technology consists of major retrofittings and new design of heating units, using the same principles as mentioned for utility boilers and heaters. The efficiency in decreasing the oxides of nitrogen formation to within the present level is estimated to be 60 percent. Best available technology is expected to be phased in during the period 1990 to 1995, assuming best practicable technology has previously been applied to existing facilities.

4.6.3 Residential and Commercial Summary

Figure 13 illustrates the combined emissions from the residential and commercial sectors, assuming the application of present technology, best practicable technology, and best available technology for the two growth scenarios.

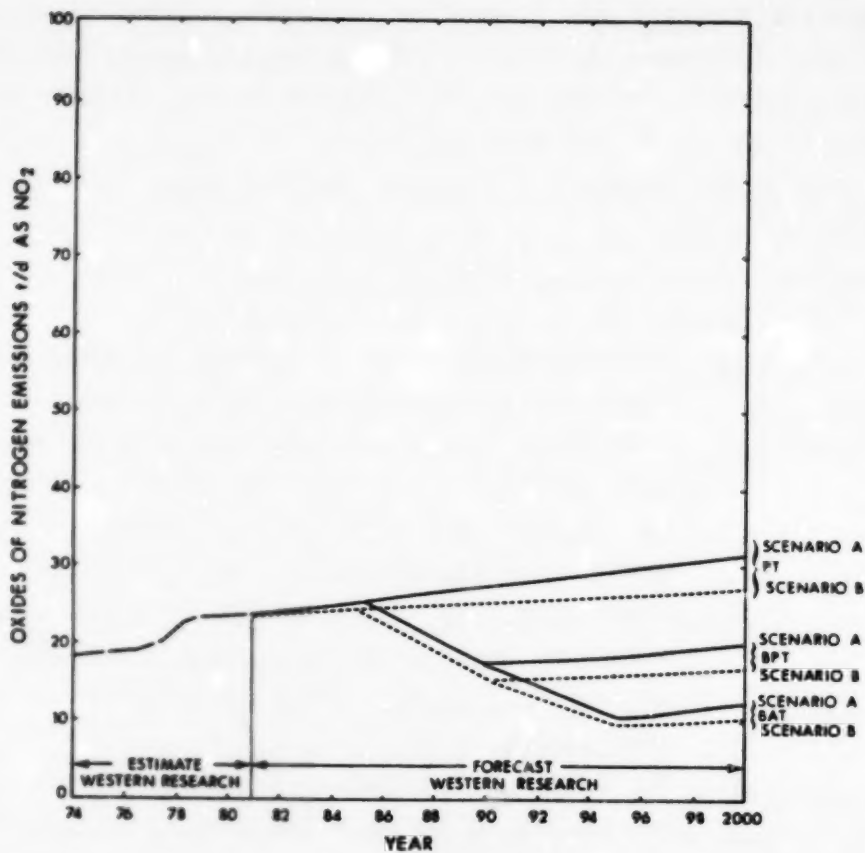


Figure 13. Residential and commercial emissions forecast.

4.7. TOTAL ALBERTA FORECAST

The characteristics of each development scenario and emission forecast are summarized, and consolidated forecasts of oxides of nitrogen emission in Alberta for the period 1980 to 2000 are presented. In addition, historical emission estimates for the period 1974 to 1981 are also summarized.

For scenarios A and B, the following characteristics apply.

4.7.1 Scenario A

1. Natural Gas Industry. High growth of marketable gas deliveries corresponding to the expanded USA and Canadian markets. Fuel gas usage as a percentage of total deliveries for the various user categories in the natural gas industry is assumed to remain constant for the forecast period.
2. Electric Utility. High growth of electric energy demand to about 63 000 Gw h in 2000, with the major portion of electric energy supplied by coal-fired power plants.
3. Oil Sands. High growth corresponding to an increase in capacity totalling 84 000 m³/d of synthetic crude oil by 2000.
4. Other Industries. Industrial growth includes expansions or additions to the petrochemical, fertilizer, and refinery industries. Growth in fuel requirements of natural gas for the other industries in Alberta is also assumed.
5. Motor Vehicles. A high population forecast of 3.8 million people by 2000 and a motor vehicle ownership ratio growth rate of 1 percent per annum are assumed.
6. Railways. Diesel fuel oil consumption by railways is forecast to grow at the historical annual rate of 3 percent.

7. Residential and Commercial. The growth of natural gas consumption by the residential and commercial sector corresponds to the high population forecast of 3.8 million by 2000.

4.7.2 Scenario B

1. Natural Gas Industry. Low growth of marketable gas deliveries corresponding to the supply of Alberta and traditional Canadian demands as well as meeting the existing US export licences. Fuel gas usage as a percentage of total deliveries by various user categories in the natural gas industry is assumed to remain constant for the forecast period.
2. Electric Utility. Low growth of electric energy demand to about 52 000 Gw h in 2000, with the major portion of electrical energy supplied by coal-fired power plants.
3. Oil Sands. Low growth forecast with no new capacity developed during the forecast period.
4. Other Industries. The forecast of natural gas requirements for other industries is assumed to be the same as that for Scenario A.
5. Motor Vehicles. Low growth corresponding to the low population forecast of 3.0 million by 2000. The motor vehicles ownership ratio was assumed to grow at a constant annual rate of 1 percent.
6. Railways. The forecast of diesel fuel oil consumption is assumed to be the same as that for Scenario A.
7. Residential and Commercial. Low growth of natural gas consumption by the residential and commercial sector corresponding to the low population forecast of 3.0 million by 2000 is assumed.

4.7.3 Consolidated Forecast

The forecast emissions for the two scenarios are outlined in Table 30 and Figure 14.

Emissions of oxides of nitrogen were forecast to grow steadily using present technology and by 2000 would reach about 1833 t/d for Scenario A and 1502 t/d for Scenario B. These represent increases of about 100 and 60 percent, respectively, from 1980 emission levels.

The relative contribution of each sector to total oxides of nitrogen emissions for the years 1980 and 2000 is shown in Figure 15. The figure also shows the impact of the application of the different levels of control technology.

The most significant increases were forecast to occur in the transportation, electric utility, and other industrial sectors. A modest increase was projected for the natural gas industry. The residential/commercial sectors were forecast to remain minor sources of oxides of nitrogen. On a percentage basis, oil sands emissions were predicted to increase substantially for Scenario A but, relative to other Alberta sources, this sector remains a relatively small source.

When best practicable technology was considered, it was applied to each source category starting in 1985 and phased in until fully applied in 1990. With this strategy, reductions in total annual emissions were forecast to occur until about 1990 when source growth again results in steady increases until the end of the forecast period. By 2000, the emission levels were forecast to be equal to or 15 percent less than 1980 levels for scenarios A and B, respectively.

Further reductions in oxides of nitrogen were achieved by the application of best available technology starting in 1990. By 2000, emission levels 50 or 60 percent lower than 1980 levels were forecast for scenarios A and B, respectively.

Table 30. Consolidated oxides of nitrogen emissions forecasts for Alberta.^a

Year	Scenario A			Scenario B		
	PT (t/d)	BPT (t/d)	BAT (t/d)	PT (t/d)	BPT (t/d)	BAT (t/d)
1980	931	931	931	931	931	931
1981	938	938	938	938	938	938
1982	1005	1005	1005	985	985	985
1983	1060	1060	1060	1035	1035	1035
1984	1196	1196	1196	1112	1112	1112
1985	1270	1270	1270	1147	1147	1147
1986	1332	1163	1163	1189	1043	1043
1987	1350	1075	1075	1208	959	959
1988	1375	998	998	1221	883	883
1989	1362	911	911	1196	800	800
1990	1379	810	810	1204	707	707
1991	1399	806	757	1220	696	641
1992	1449	811	673	1246	686	583
1993	1490	820	609	1275	701	525
1994	1533	831	547	1304	705	468
1995	1577	830	442	1334	704	385
1996	1626	857	445	1368	721	385
1997	1674	881	451	1398	735	388
1998	1726	909	462	1431	754	395
1999	1778	937	467	1466	773	384
2000	1833	966	478	1502	792	404

^aas NO₂

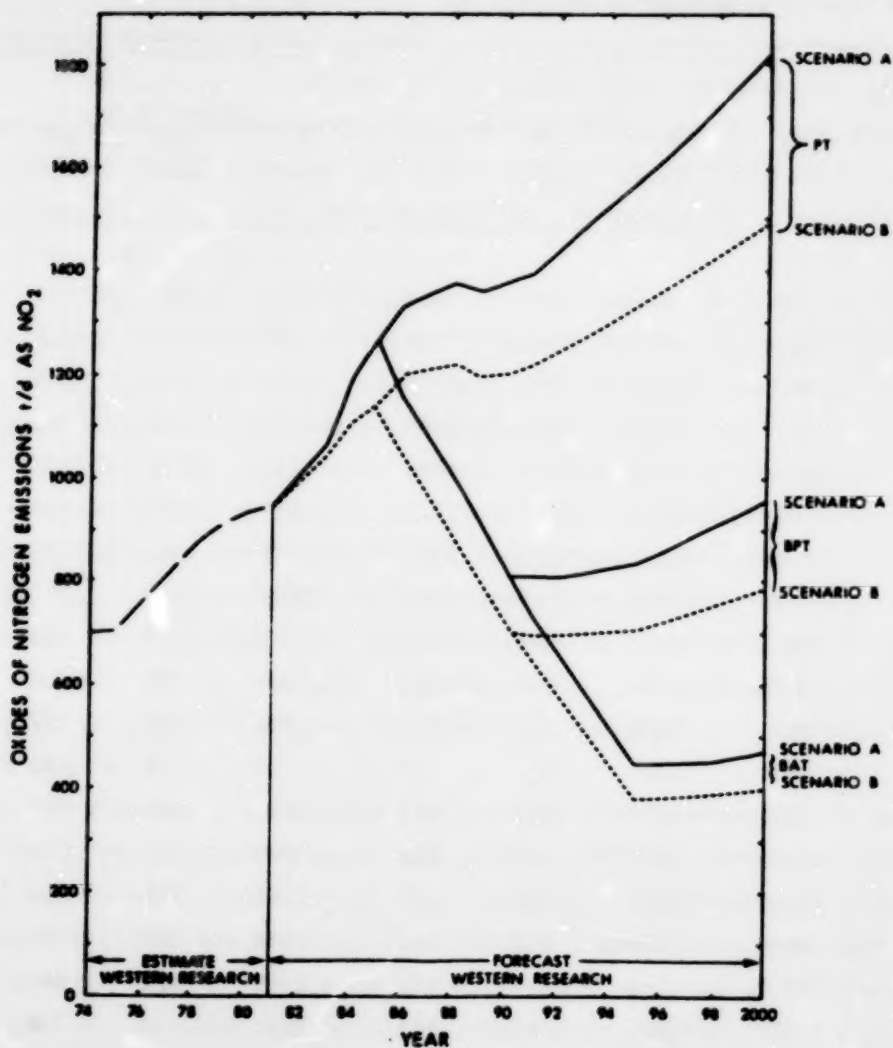
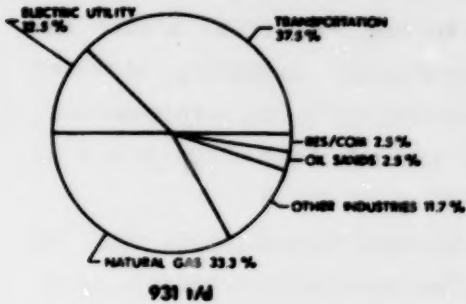


Figure 14. Total Alberta oxides of nitrogen emissions forecast 1980 to 2000.

EMISSION ESTIMATE FOR 1980

TOTAL OXIDES OF NITROGEN EMISSIONS
tAJ ARE EXPRESSED AS NO₂

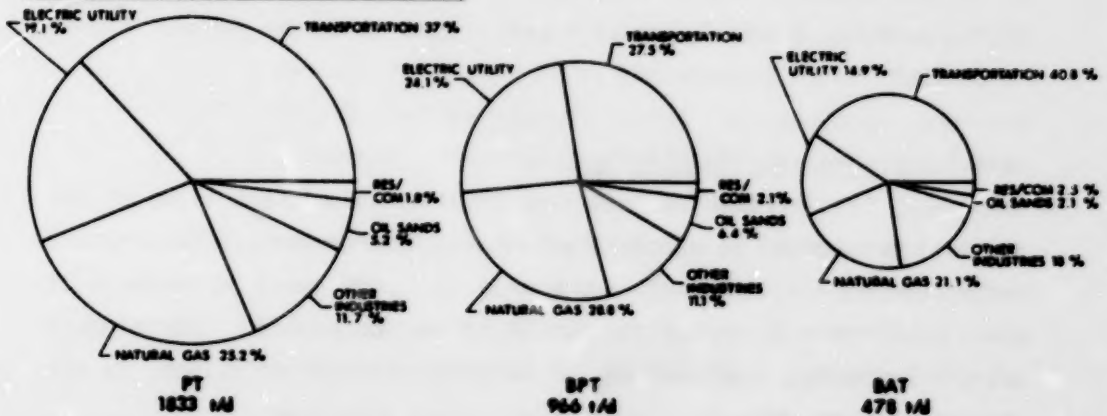
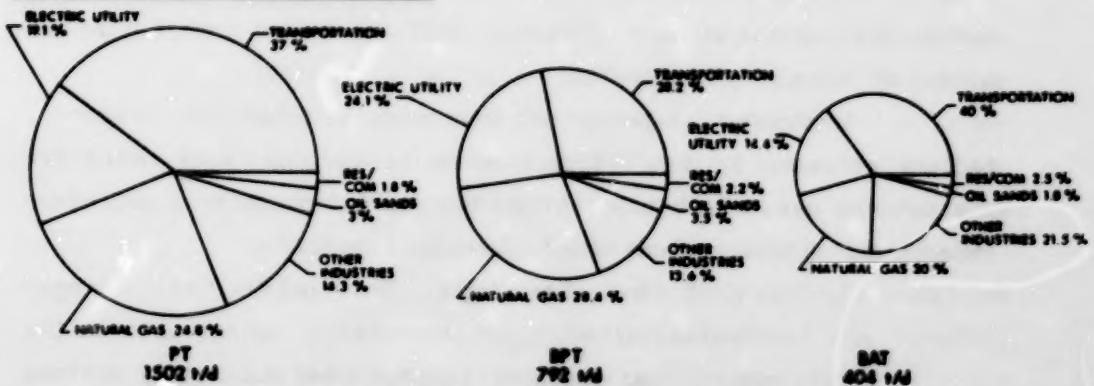
SCENARIO A EMISSION FORECAST FOR 2000**SCENARIO B EMISSION FORECAST FOR 2000**

Figure 15. NO_x emission comparison by sector and technology for 1980 and 2000.

4.7.4 Other Strategies

One strategy that may also be considered is the application of best practicable technology to new industrial plants and utilities and no alteration of existing or presently approved facilities. This strategy would have the following consequences:

1. The forecast based on present technology would be followed to the year 1990.
2. The moderate rate of increase in emissions depicted between 1990 and 2000 for the best practicable technology would be experienced.

By year 2000, emissions would be about 1550 and 1300 t/d for scenarios A and B, respectively, some 65 to 40 percent higher than 1980 levels (Figure 14).

4.7.5 Forecast Sensitivity

The forecast is most sensitive to the contributions of the natural gas industry, electric utilities, transportation sectors, and other industries. These four sources make up about 90 percent of the total emissions for the entire forecast period. The biggest single category, representing 37 percent of total emissions, is the transportation sector.

For at least the next twenty years, oil sands plants, and residential and commercial sources will be minor contributors of oxides of nitrogen in Alberta.

In developing the growth and emission potential forecasts, factors relevant to the ultimate emission forecast were noted for the natural gas, electric utility, transportation sectors, and other industries. These include the following:

1. **Natural Gas Industry.** The oxides of nitrogen emission factor for reciprocating engines used in the natural gas industry has not been accurately defined and actual emissions may be 25 percent lower than this forecast indicates. Reciprocating engines are responsible for 90 percent of the oxides of nitrogen emissions attributed to the natural gas industry, and

a 25 percent reduction in the emission factor would lead to a 22 percent reduction in emissions for this industry. This is equivalent to approximately 88 t/d over the entire forecast period for the present technology analysis.

2. **Electric Utilities.** If non-fossil fuel sources of electric power are developed, a decrease in the growth rate of emissions will result. For the case where a major hydro project and the western grid are developed in the last half of the forecast period, net impact on oxides of nitrogen emissions would be 40 t/d. This is an average reduction of about 15 percent for the 1990 to 2000 period.
3. **Transportation.** Growth rates for passenger car and commercial vehicle populations may be higher than that predicted for Scenario A and lower than that predicted by Scenario B. Applying the most optimistic and pessimistic forecasts leads to a potential increase of 115 t/d in emissions for Scenario A and potential decrease of 88 t/d for Scenario B in the year 2000 using present technology.
4. **Other Industries.** The average type and size of industrial boilers in Alberta has not been accurately defined. The emission factor for industrial power boilers was used to estimate emissions for other industries. However, if Alberta's industrial boilers can be represented by industrial steam boilers, the emission factor may be as much as 60 percent lower. This is equivalent to approximately 120 t/d reduction in emissions during the latter part of the forecast period for the present technology analysis.

Taking all of these factors together results in a maximum emission forecast of 1950 t/d and a minimum forecast of 1170 t/d by 2000 using present technology. These factors would also affect the forecasts using best practicable and best available technology but the magnitude of the impacts would be reduced.

5. CONCLUSIONS AND RECOMMENDATIONS

The forecast shows that without the determined application of improved technology, oxides of nitrogen emissions will increase by 60 to 100 percent by 2000. The application of best practicable control technology to all future sources, be they industrial, commercial, residential, or transportation will not, on its own, result in a zero increase in emissions compared to 1980 levels. Improved technology will have to be applied to some existing facilities if this objective is to be achieved.

Full application of best practicable and best available technology has the potential of reducing oxides of nitrogen emission levels in 2000 by about 10 and 55 percent, respectively, compared to 1980 levels.

Forecasting efforts for the industrial sector point out the need for an improved understanding of where energy is used and of the emission factors that are characteristic of energy consuming devices used in Alberta. Emission reporting formats that provide energy consumption and emission factors based on energy by user category and annual analysis of these reports would, in a reasonable time period, establish the required information.

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7. APPENDIX

This appendix contains tabulated summary data for the oxides of nitrogen emission forecasts according to the levels of control technology applied for scenarios A and B. The data are categorized according to the following sectors: transportation, residential/commercial, electric utilities, oil sands, other industries, and natural gas. The totals correspond to the data contained in Table 30.

Table 31. Oxides of nitrogen emissions forecast: scenario A, present technology.^a

Year	Transportation (t/d)	Residential/ Commercial (t/d)	Electric Utilities (t/d)	Oil Sands (t/d)	Other Industries (t/d)	Natural Gas (t/d)	Total (t/d)
1980	349	23	116	24	109	310	931
1981	352	23	120	27	112	304	938
1982	360	23	140	39	112	331	1005
1983	374	23	152	43	112	356	1060
1984	386	23	164	44	127	452	1196
1985	398	23	176	46	127	500	1270
1986	417	24	186	46	143	516	1332
1987	430	26	195	46	156	497	1350
1988	446	26	205	46	171	481	1375
1989	462	26	214	46	179	435	1362
1990	476	27	224	46	179	427	1379
1991	497	27	236	49	179	421	1399
1992	515	27	248	55	189	415	1449
1993	535	28	260	59	189	419	1490
1994	554	28	272	65	195	419	1533
1995	573	30	284	70	195	475	1577
1996	593	31	297	75	200	430	1626
1997	614	31	310	81	200	438	1674
1998	635	32	323	86	205	445	1726
1999	656	32	336	91	210	453	1778
2000	677	33	350	97	215	461	1833

^a as NO₂

Table 32. Oxides of nitrogen emissions forecast: scenario A, best practicable technology.^a

Year	Transportation (t/d)	Residential/ Commercial (t/d)	Electric Utilities (t/d)	Oil Sands (t/d)	Other Industries (t/d)	Natural Gas (t/d)	Total (t/d)
1980	349	23	116	24	109	310	931
1981	352	23	120	27	112	304	938
1982	360	23	140	39	112	331	1005
1983	374	23	152	43	112	356	1060
1984	386	23	164	44	127	452	1196
1985	398	23	176	46	127	500	1270
1986	352	22	171	46	120	452	1163
1987	326	21	166	46	112	404	1075
1988	312	19	161	46	105	355	998
1989	288	18	155	46	97	307	911
1990	267	17	150	28	90	258	810
1991	256	17	158	30	90	255	806
1992	249	17	166	34	95	250	811
1993	244	17	174	37	95	253	820
1994	241	18	181	40	98	253	831
1995	226	18	189	43	98	256	830
1996	234	19	198	46	100	260	857
1997	241	19	207	50	100	264	881
1998	249	19	216	53	103	269	909
1999	258	20	225	56	105	273	937
2000	266	20	223	62	108	278	966

^a as NO₂

Table 33. Oxides of nitrogen emissions forecast: scenario A, best available technology.^a

Year	Transportation (t/d)	Residential/ Commercial (t/d)	Electric Utilities (t/d)	Oil Sands (t/d)	Other Industries (t/d)	Natural Gas (t/d)	Total (t/d)
1980	349	23	116	24	109	310	931
1981	352	23	120	27	112	304	938
1982	360	23	140	39	112	331	1005
1983	374	23	152	43	112	356	1060
1984	386	23	164	44	127	452	1196
1985	398	23	176	46	127	500	1270
1986	352	22	171	46	120	452	1163
1987	326	21	166	46	112	404	1075
1988	312	19	161	46	105	355	998
1989	288	18	155	46	97	307	911
1990	267	17	150	28	90	258	810
1991	244	15	132	30	90	226	737
1992	231	14	114	34	88	194	673
1993	219	13	95	37	86	162	609
1994	208	12	77	40	84	130	547
1995	190	10	58	10	82	96	442
1996	189	11	61	10	80	94	445
1997	190	11	63	11	80	96	451
1998	194	11	66	11	83	97	462
1999	194	11	64	12	83	99	467
2000	195	12	71	13	86	101	478

^a as NO₂

Table 34. Oxides of nitrogen emissions forecast: scenario B, present technology.^a

Year	Transportation (t/d)	Residential/ Commercial (t/d)	Electric Utilities (t/d)	Oil Sands (t/d)	Other Industries (t/d)	Natural Gas (t/d)	Total (t/d)
1980	349	23	116	24	109	310	931
1981	352	23	120	27	112	304	938
1982	346	23	134	39	112	331	985
1983	359	23	142	43	112	356	1035
1984	369	23	151	44	127	398	1112
1985	377	23	160	46	127	414	1147
1986	392	23	168	46	143	427	1199
1987	401	24	176	46	156	405	1208
1988	411	24	184	46	171	385	1221
1989	419	24	192	46	179	336	1196
1990	430	24	201	46	179	324	1204
1991	444	24	210	46	179	317	1220
1992	455	24	218	46	189	314	1246
1993	468	24	227	46	189	321	1275
1994	480	24	236	46	195	323	1304
1995	493	24	245	46	195	331	1334
1996	505	26	253	46	200	338	1368
1997	518	26	261	46	200	347	1398
1998	530	26	269	46	205	355	1431
1999	543	27	277	46	210	363	1466
2000	556	27	286	46	215	372	1502

^a as NO₂

Table 35. Oxides of nitrogen emissions forecast: scenario B, best available technology.^a

Year	Transportation (t/d)	Residential/ Commercial (t/d)	Electric Utilities (t/d)	Oil Sands (t/d)	Other Industries (t/d)	Natural Gas (t/d)	Total (t/d)
1980	349	23	116	24	109	310	931
1981	352	23	120	27	112	304	938
1982	346	23	134	39	112	331	985
1983	359	23	142	43	112	356	1035
1984	369	23	151	44	127	398	1112
1985	377	23	160	46	127	414	1147
1986	332	20	155	46	120	370	1043
1987	305	20	150	46	112	326	959
1988	287	18	145	46	105	282	883
1989	262	17	140	46	97	238	800
1990	242	15	136	28	90	196	707
1991	232	15	141	28	90	192	696
1992	222	15	147	28	95	189	696
1993	217	15	152	28	95	194	701
1994	211	15	158	28	98	195	705
1995	198	16	164	28	98	200	704
1996	204	16	169	28	100	204	721
1997	208	16	174	28	100	209	735
1998	213	16	180	28	103	214	754
1999	219	17	185	28	105	219	773
2000	223	17	191	28	108	225	792

^a as NO₂

Table 36. Oxides of nitrogen emissions forecast: scenario B, best available technology.^a

Year	Transportation (t/d)	Residential/ Commercial (t/d)	Electric Utilities (t/d)	Oil Sands (t/d)	Other Industries (t/d)	Natural Gas (t/d)	Total (t/d)
1980	349	23	116	24	109	310	931
1981	352	23	120	27	112	304	938
1982	346	23	134	39	112	331	985
1983	359	23	142	43	112	356	1035
1984	369	23	151	44	127	398	1112
1985	377	23	160	46	127	414	1147
1986	332	20	155	46	120	370	1043
1987	305	20	150	46	112	326	959
1988	287	18	145	46	105	282	883
1989	262	17	140	46	97	238	800
1990	242	15	136	28	90	196	707
1991	220	13	119	28	90	171	641
1992	206	13	102	28	88	146	583
1993	194	11	85	28	86	121	525
1994	182	10	68	28	84	96	468
1995	165	10	50	7	82	72	385
1996	162	10	52	7	80	74	385
1997	162	10	53	7	80	76	388
1998	163	10	55	7	83	77	395
1999	158	10	57	7	83	79	394
2000	162	10	58	7	86	81	404

^a as NO₂